Exhibit No. 300

OPC – Exhibit 300
Lena M. Mantle
Direct
File No. ER-2024-0189

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

DIRECT 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 NOS. ER-2024-0189

** _____ **
Denotes Confidential Information that has been redacted

June 27, 2024

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OF

LENA M. MANTLE

EVERGY MISSOURI WEST
FILE NO. ER-2024-0189

INTRODUCTION

Q. What are your name and business address?

A. My name is Lena M. Mantle, and my business address is P.O. Box 2230, Jefferson City, Missouri 65102.

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

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as a Senior Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the OPC.

Q. What recommendations to the Commission are you supporting in this testimony?

A. I make the following recommendations:

1. As a result of Evergy Missouri West's ("Evergy West") resource planning decisions that have resulted in a dependency on spot market energy, the Commission should modify the sharing mechanism in Evergy West's fuel adjustment clause ("FAC") from 95% customers/5% Evergy West ("95/5") to 75% customers/25% Evergy West ("75/25"); and
2. 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 Evergy West's Crossroads facility in Clarksdale, Mississippi to Evergy West's customers in Missouri.

Q. What is your experience, education, and other qualifications, particularly on the topics to which you are testifying?

A. Prior to my employment at the OPC, I worked for the Staff of the Missouri Public Service Commission ("Staff") from August 1983 until I retired as Manager of the Energy Unit in December 2012. During my employment at the Missouri Public Service Commission ("Commission"), I worked as an Economist, Engineer, Engineering Supervisor, and Manager of the Energy Unit.

I began employment at the OPC in my current position as Senior Analyst in August 2014. In this position, I have provided expert testimony in electric and water cases before the Commission on behalf of the OPC. I am a Registered Professional Engineer in the State of Missouri.

Attached as Schedule LMM-D-1 is a brief summary of my experience with the OPC and Staff, and a list of the Commission cases I filed testimony in, Commission rulemakings I participated in, and Commission reports in rate cases that I contributed to as Staff.

Q. What is your experience regarding Missouri's fuel adjustment clauses?

A. After the Missouri Legislature passed Section 366.266, RSMo in 2005, enabling the electric utilities to request an FAC, I was instrumental in the development and application of the Commission's FAC rules and the FACs of the electric utilities in Missouri. I have provided testimony regarding FACs in numerous general rate cases, FAC rate change cases, and FAC prudence cases, both during my time on the Commission Staff and during my employment at the OPC.

Attached as Schedule LMM-D-2 is the *Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper* that I wrote to provide background and a description on various aspects of the FAC in Missouri. This whitepaper provides an explanation of the operation of FACs in Missouri, including

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the FAC of Evergy West, and the terms used in discussing Evergy West's FAC in this testimony.

Q. What is your experience regarding Missouri investor-owned electric utility long-term resource planning?

A. My experience in electric utility resource planning began in the late 1980s when I worked in the Research and Planning Department for the Commission Staff. With abundant coal plants and the addition of nuclear generation plants for two of Missouri's electric utilities,[1] it was evident that the electric utilities in Missouri had over built. Attempting to avoid another overbuilding of capacity, the Commission tasked its Research and Planning Department with reviewing the utilities' current resource planning processes and developing rules for the Commission regarding electric utility resource planning. I was a member of that team. The team did a comprehensive review of current resource planning practices of the Missouri investor-owned utilities and the current (at that time) state-of-the-art electric utility resource planning practices across the nation. Utilizing this information, the team developed resource planning proposed rules with input from the electric utilities and other parties in numerous workshops. The Commission's Electric Utility Resource Planning Chapter 22 (20 CSR 4240-22) became effective on May 6, 1993. Much later, as Manager of the Energy Department, I was also instrumental in the revisions of the Chapter 22 Electric Utility Resource Planning[2] rules ("Chapter 22"). These revised rules became effective June 30, 2011.

[1] Union Electric Company's Callaway Nuclear Plant and Kansas City Power & Light Company's Wolf Creek Nuclear Plant.

[2] At that time the word "integrated" was used to designate that demand-side resources were included in the resource planning process. With the expectation that integrating demand-side resources would become a normal part of good planning, it was decided to name this rule and process in Missouri "Resource Planning."

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DEFINITIONS OF KEY TERMS

Q. What terms do you use in your testimony that are critical in understanding resource planning and the FAC?

A. It is critical to correctly understand capacity, energy, demand, and load requirement including the differences and the interactions between them. These terms are often used imprecisely yet it is important to understand and use them correctly.

Q. Would you provide a definition of capacity as it is used in your testimony?

A. I use capacity as it is defined in the Commission's Chapter 22 as follows:

> Capacity means the maximum capability to continuously produce and deliver electric power via supply-side resources or the avoidance of the need for this capability by demand-side resources.[3]

The capacity of a generation resource is the maximum output it can physically produce. With respect to utility scale generation resources, it is measured in megawatts ("MW").

Q. Would you define energy as you use it your testimony?

A. I use energy as the Commission defines energy in Chapter 22 as follows:

> Energy means the total amount of electric power that is generated or used over a specified interval of time measured in kilowatt-hours (kWh).[4]

The energy generated by utility scale generation resources is typically measured in megawatt-hours ("MWh") which is equivalent to 1,000 kWh.

[3] 20 CSR 240-22.020(4).
[4] 20 CSR 240-22.020(19).

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Q. Both of these definitions are a measure of electric power. Can they be used interchangeably?

A. No. While capacity and energy are often used interchangeably, they should not be. They are measurements of different aspects of electricity.

Q. Are they related?

A. They are related to the extent that both are impacted by design and usage of a given generating unit. To clarify, consider this example: there is a sign in the elevator that states its capacity, *i.e.* how many people the elevator can hold at a given time. This limits the amount of people that can be in the elevator at any given time. However, it gives no information on the number of people that ride in the elevator each day. In a given day the elevator may make 10 trips with 20 people each time meaning 200 rides (10 x 20) were given. The next day the elevator may not move because the building is closed resulting in zero rides being given that day. The capacity is the same, 20 people, no matter how many rides are given. However, the number of rides given cannot be determined from the capacity of the elevator.

Similarly, the capacity of a generator is the limiting criteria for the maximum amount of energy a generator can produce. A plant with a capacity of 100 MW cannot generate 200 MWh of energy in any given hour just as an elevator with a capacity of 20 people cannot hold 40 people. However, it is not correct to say that same plant is producing 100 MWh of energy at every hour of every day just as that same elevator is not necessarily carrying 20 people with every trip. The capacity and energy produced by the generator are thus related, in as far as they are dependent on its design, but are measuring very different things.

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Q. The Commission's definition of energy includes the total amount of electric power that is used over a specified interval of time. How is this connected to the energy that a power plant produces?

A. Energy is a term that is also used as a measurement of how much electricity a customer or group of customers consumes over a period of time. Electric utilities are required to meet the energy requirements of their customers.

Q. Is this energy requirement also referred to as load requirement?

A. This is one measure of load requirement. Load requirement is measured in peak demand and energy. Peak demand (or demand) is the highest amount of electricity used over a set time-period. Each day has a peak demand as does the week, month, and year. The energy is the sum of the hourly demands over the set time period.

The following example should help explain this. If over ten hours, a customer uses 50 MW in nine hours and 550 MW in one hour, then the customer's peak demand in that ten hours is 550 MW (the maximum amount of energy used in an hour over the ten hours) and the energy used over that ten hours is 1,000 MWh. (1,000 MWh = (50 MW x 9 hours) + (550 x 1 hour)). In this testimony, when I use the words "load requirement" or "load" I am referring to both the peak demand and energy of the customers.

Q. Would a resource that provides 1,000 MWh over that ten hours be able to meet this load requirement?

A. Not necessarily. The table below is provided to help explain the differences between these terms.

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Table 1
Example of Peak, Capacity, and Energy

Hour	Customer Demand	Generator A	Generator B
1	50	100	0
2	50	100	0
3	50	100	0
4	50	100	0
5	550	100	550
6	50	100	0
7	50	100	0
8	50	100	0
9	50	100	0
10	50	100	0
Total	1,000	1,000	550
Peak (MW)	550		
Capacity (MW)		100	550
Energy (MWh)	1,000	1,000	550

In this example, the peak demand for the customer over these ten hours is the maximum hourly demand of 550 MW. The energy needs of the customer is the sum of the demands of each hour or 1,000 MWh. This is the load requirement that the utility is required to meet – both the peak and the energy needs of the customer.

Generator A has a capacity of 100 MW. That is the maximum it can generate in an hour. If it generated its maximum every hour for these ten hours, then it could generate 1,000 MWh of energy. However, it cannot meet the peak demand of the customer of 550 MW since the most it can produce is 100 MW.

Generator B has the capacity to meet the peak demand of the customer of 550 MW. However, it cannot meet the load requirement of the customer in the other nine hours.

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EVERGY WEST'S FAC SHARING MECHANISM SHOULD BE MODIFIED TO 75% CUSTOMERS /25% EVERGY WEST

Q. Why are you recommending the Commission modify the sharing mechanism in Evergy West's FAC to 75% customers/25% Evergy West?

A. The current sharing mechanism of 95% customers/5% Evergy West has not provided Evergy West enough of an incentive to prudently meet the energy needs of its customers. Evergy West has continuously made the resource planning decision to rely on the SPP energy market to meet the energy needs of its customers instead of building or acquiring cost-effective generation that meets the energy needs of its customers. Based on my experience with Evergy West and its predecessors, KCP&L – Greater Missouri Operations Company, and Aquila, Inc., I am confident that if Evergy West did not have an FAC, it would have acted differently, putting steel in the ground, or entering into long-term firm contracts for the provision of energy instead of relying on the volatile SPP energy market.

Q. What demonstrates that Evergy West is relying on the SPP energy market?

A. Evergy West pays SPP for every MWh of energy used by its customers and receives revenue for every MWh it produces. Table 2 below shows, for the last four prudence periods,[5] the cost of energy from the SPP market to meet customer load requirements and the revenues from generation sold to SPP for Evergy West and Evergy Metro from Staff's filed prudence reports.

[5] December 2016 through November 2022 for Evergy West. January 2017 through December 2022 for Evergy Metro.

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Table 2
Energy Market Margin by Prudence Period

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Over these four prudence periods, Evergy West has spent $748 million more on non-firm short-term energy for its customers than it received in revenues from the SPP market. This does not include the $314.6 million costs of Storm Uri in February 2021. At the same time, its sister utility, Evergy Meto, received revenues above what it paid of $465 million. That is a $1.2 BILLION swing between two utilities that faced the same market, the same weather, and have the same management. The difference between the two utilities is that during the six calendar years of 2017 through 2022, Evergy Metro had generation above what its customers needed and Evergy West relied on the SPP market for approximately half of the energy its customers needed.[7]

[6] February 2021 short-term energy costs and off-system sales revenues are normalized due to Storm Uri.
[7] The workpaper that shows this calculation is provided as Schedule LMM-D-3.

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Q. What is the relationship between resource planning and the FAC?

A. Electric utility resource planning decisions directly impact the costs and revenues that flow through the FAC for decades after the decision. Market prices that change every five minutes are mitigated by decisions to acquire "insurance" (generation resources) that can take years to implement, *i.e.* build, and which are intended to meet customers' needs for decades. Consequently, the "incurrence" of the cost of fuel, whether it be uranium, coal, natural gas, or oil, and purchased power cost that is passed to customers through an FAC is set in motion by the decision decades earlier by the electric utility to not build, or to build and what to build.

Q. What is resource planning?

A. The Commission defines resource planning as:

> Resource planning means the process by which an electric utility evaluates and chooses the appropriate mix and schedule of supply-side, demand-side, and distribution and transmission resource additions and retirements to provide the public with an adequate level, quality, and variety of end-use energy services.[8]

Resource planning decisions are a minimization of fixed costs (*e.g.* cost to build a plant) and variable costs (*e.g.* cost to run a plant that are included in the FAC) taking into account market prices, reliability concerns, and critical uncertain factors. Each resource type has unique characteristics. A prudent resource plan results in a resource portfolio that meets the load requirements of the utility's customers utilizing the characteristics of the various resources, both demand and supply side, to minimize price volatility while assuring customers a reliable source of energy to cost-effectively meet their energy needs.

[8] 20 CSR 240-22.020(53).

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Q. Why is electric utility resource planning so complex?

A. Electricity is a secondary energy source. It results from the conversion of other energy forms such as natural gas, coal, or uranium, or the energy inherent in wind, sunshine, or the flow of water in a river. There are also a number of different ways to convert these energy forms to electricity making the task of determining the optimal sources to meet projected customer load requirements across various futures while minimizing costs and meeting reliability requirements a very complex task.

For example, a nuclear plant is designed to run continuously and has a low, stable fuel cost. It would not be appropriate to build a nuclear plant if the need was only for a few hours of the year when it is really hot because of the large, fixed cost of building nuclear resources. Likewise, a natural gas combustion turbine ("CT") would not be appropriate to meet the constant energy requirements of a large data center. It is relatively inexpensive to build but, across decades, its fuel costs can be volatile and, as utilities have experienced during the past few years, the natural gas supply can be disrupted. CTs are not the most efficient generators of electricity and are not designed to run continuously for long periods of time. Due to the risk of volatile fuel cost, potential for supply disruptions, and the CTs design, it is not the appropriate type of resource to meet the continuous, large load requirements of a data center. However, since CTs can be dispatched as needed, using natural gas CTs to meet energy requirements that only exist a few hours of the year is more cost-effective than resources with high fixed costs but low variable costs to generate electricity.

Q. What about renewable generation resources like wind and solar?

A. Like natural gas and coal generation, renewable generation has its benefits and owned wind and solar have no fuel costs. However, they have limited availability that does not always match customers' load requirements restricting their applicability. Solar is typically available during the hottest days of the year when cooling load is the

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greatest and market prices are high. However, if the need is for electricity to heat buildings in the winter, solar is unavailable in the middle of the night when it is the coldest. Wind energy may be available during those cold windy nights but is often not available in the hot humid nights of summer. Too much dependence on energy from renewable resources often leaves the utility at the risk of not having adequate energy to meet its customers' needs and having to buy energy from the market at times when prices are high. While these low-cost energy resources are valuable, their limited availability needs to be properly accounted for in the resource planning process.

Q. Is there a role for purchased power in the resource planning process?

A. Yes. There are two types of purchased power, bilateral contracts also known as purchased power agreements ("PPA") and energy market purchases. Both have a role in resource planning. However, the availability and pricing of PPAs is determined by the overbuilding of other utilities or the ability of the power producer to make a profit – risks that need to be taken into account in the resource planning process.

Q. Would you explain the role of PPAs in resource planning?

A. Purchased power contracts for capacity and/or energy are a tool that can, and should, be used to fill small gaps in resource planning. Generation resources are typically added in bulk. Load typically increases in small increments. PPAs can be useful to delay the addition of a resource for a few years waiting for load to grow into the bulkiness of a resource. However, PPAs also have limitations. Purchased power contracts for capacity, like Evergy West has with its sister utility Evergy Metro, typically do not include a cost for energy from the resource. This means the utility ends up purchasing energy from the market. If a utility has an FAC like Evergy West that includes the cost of purchased power, relying on the market results in the risk of

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volatile market prices being placed, not on the utility that entered into the capacity only contract, but on the customers that have no role in resource planning.

Q. Can having an FAC influence resource planning decisions?

A. Yes. Without a FAC, the utility is responsible for net energy and purchased power costs above what are included in permanent rates. This means that the utility itself is exposed to the risk of any major price fluctuations in the cost of fuel or the energy market. If fuel and purchased power costs are greater than what is included in rates, the utility absorbs the increased cost and can come to the Commission requesting a general rate increase to cover future increased costs. If there is no FAC, the utility would want to take out platinum "insurance" *i.e.* building whatever resources it believes is necessary to minimize its risk of having to absorb any energy related costs that might arise due to this risk.[9]

Having a FAC removes the risk of the utility not recovering its fuel and purchased power costs and places the risks of the utility making an incorrect resource planning decision on its customers. Increasing fuel or market prices are just passed on to customers with negligible impact on shareholders.[10] Some resource planning decisions, such as entering into PPAs with no capacity charges (only charges for energy which are recoverable through the FAC), remove all risks

[9] Without a FAC, the utility also gets to retain the savings when net FAC costs are below what are in permanent rates. In Missouri a FAC is optional. The electric utilities have determined the likelihood of costs below what is included in rates is low and the risk that costs will be above what is included in rates is unacceptable and all have requested, and received, an FAC. Thus, all this risk that was unacceptable to the utility is now on its customers.

[10] The costs and revenues used to determine the FAC base factor are included in revenue requirement, *i.e,* there is a base amount of fuel and purchased power costs included in permanent rates. Evergy West's FAC includes a 95/5 sharing of the net costs **above** the FAC costs and revenues that are included in permanent rates. The impact on cost recovery of total FAC costs (cost recovered in permanent rates plus cost recovered in the FAC rate) given variances from the FAC costs included in permanent rates is described on pages 12 – 13 of the FAC whitepaper attached as Schedule LMM-D-2. This whitepaper shows that, even when actual costs are 150% of the FAC costs included in base rates, Evergy West would recover over 98% of the total actual FAC costs it incurred.

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of building plant from the shareholder and puts all the risk of increased energy costs on the customers. The same is also true of short-term capacity contracts that do not include energy. [11] With an FAC, if the utility builds, the shareholders earn a return on the capital investment and recover costs while the customers get the advantage of the hedge of the generation plant. If the utility does not build and instead choses to rely on the RTO, it can use the capital to invest in other areas and not worry about the shareholders having to pay if the market goes wild. The customers see lower base rates but are exposed to the volatility of the market and hence may pay even higher bills due to increased FAC costs.

Q. Has having an FAC affected the resource planning of Evergy West?

A. Yes. While it is not obvious in the resource planning documents filed with the Commission, Evergy West's action, or in this instance inaction, speaks louder than words in a resource planning document. In the last resource plan that Evergy West, then known as Aquila, filed prior to being acquired by Great Plains Energy, Inc.,[12] Aquila estimated that under normal conditions its generation resources could only generate 74% of the energy its customers' need, *i.e.* it was depending on the market to cover at least 26% of its customers' load requirements. To correct for this fact, Aquila's preferred resource plan was to add **_____ _____**[13] These proposed owned resources were in addition to its 153 MW portion of the Iatan 2 coal plant that was under construction at that time.

SPP did not have a day-ahead energy market and no investor-owned electric utility in the state of Missouri had an FAC when Aquila filed this resource plan that

[11] Evergy West's FAC includes the capacity costs of PPAs of less than one year.
[12] Now known as Evergy, Inc.
[13] Case No. EO-2007-0298, *In the Matter of the Resource Plan of Aquila, Inc. d/b/a Aquila Networks-MPS and Aquila Networks L&P pursuant to 4 CSR 240-Chapter 22.* The capacity balance sheet for Aquila's preferred plan in Case No. EO-2007-0298 is attached as Schedule LMM-D-5.

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showed that the best resource plan for Aquila and its customers was to add 775 MW of capacity. Aquila's preferred resource plan was to "buy" the proper insurance policy (*i.e.* building generation resources) it believed was necessary to minimize its risk of having to absorb any energy related costs. This behavior changed drastically once the Commission approved an FAC for Aquila.

The Commission approved an FAC for Aquila effective July 5, 2007, five months after this resource plan was filed with the Commission.[14] The only resource additions by Aquila, now known as Evergy West, since the time the Commission approved an FAC for Aquila has been (1) PPAs for wind energy that Evergy West claims that it entered into not to meet their customers' energy requirements (or to meet Missouri renewable energy standards), but for what Evergy West has termed "economic reasons,"[15] and (2) the merchant Crossroads Energy Facility when Evergy West's parent company could not get any buyers for it. No other resources have been added to Evergy West's resource portfolio despite Aquila's 2007 resource plan that showed that it needed to add 775 MW of owned generation capacity by 2023.[16]

In addition to not adding any resources to meet its customers' load requirements since the filing of that preferred plan, Evergy West retired the only coal plant of which it had sole control in 2018 reducing its capacity by 400 MW. Evergy West did not add any resource to replace the capacity or energy generation capabilities of this plant that it showed running through the entire 20-year planning horizon in its 2007 preferred resource plan.

[14] Case No. ER-2007-0004, *In the Matter of Aquila, Inc. d/b/a Aquila Networks-MPS and Aquila Networks-L&P, for Authority to File Tariffs Increasing Electric Rates for the Service provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Service Area.*
[15] It projected that these PPAs would create revenues from the SPP energy market greater than the contracted price for these PPAs thus being "economic."
[16] Evergy West has acquire 22% of the Dogwood facility as of June 1, 2024.

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As a result of these decisions, Evergy West is now facing both a substantial capacity and energy shortage. In its latest resource plan update, Evergy West estimates it can only generate 56% of the energy its customers needed in 2023.[17] Evergy West relies on its sister utility Evergy Metro's excess capacity to meet its SPP reserve requirement and on the energy supplied through SPP's day ahead market to meet the remaining 44% of its customers' energy needs.

Q. How does this demonstrate that having an FAC has impacted Evergy West's resource planning?

A. The drastic change between what Evergy West (then Aquila) intended to do prior to receiving an FAC and what occurred after the Commission approved the Company's FAC clearly indicates that the FAC changed the Company's resource planning strategy. Being a member of the SPP has assured Evergy West that there will be energy for it to purchase. The development of the SPP day-ahead energy market means Evergy West does not have to enter into bilateral contracts for that energy. Having an FAC means it can recover from customers the costs it incurs by relying on others for energy through PPAs and the energy market. This gives it the resource planning option of not having to expend capital and meet its customers' needs, with very little risk being placed on its shareholders. Having an FAC removes the risk of Evergy West not recovering its fuel and purchased power costs and places the risks of Evergy West making an incorrect decision on its customers.[18] The cost of energy

[17] 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.

[18] While Section 386.266.5(4) RSMo. requires a prudence audit no less frequency than 18-month increments, finding and proving imprudence is a difficult task and is a minimal risk for the utility.

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from the market is just passed on to customers with negligible impacts on shareholders.[19]

Q. Would Evergy West have built resources if it did not have an FAC?

A. Based on my history with utilities in Missouri, I believe it would have. Prior to being granted an FAC, the electric utilities in Missouri rates were set to recover the normalized fuel and purchased power that was included in permanent rates. If actual costs were below the normalized fuel and purchased power amount included in the rates, the utility was praised for being wise in its procurement of and the savings of fuel and purchased power costs increased its earnings. Savings were not passed to the customers. However, customers had stable rates that did not change every few months.

If fuel and purchased power costs were above what was included in rates, the utility was considered the victim of a volatile market and it had to absorb the increased cost. If the increased costs continued or became very large and the utility was not able to offset the increase with savings in other operations, it would request an increase in its rates from the Commission in a general rate case where all costs and revenues were examined. Customers' rates only increased after a review of all costs – fuel and non-fuel.

With no FAC, the utility would take out platinum "insurance" i.e. building whatever resources it believed was necessary to minimize its risk of having to absorb any energy related costs. Customers paid the capital costs of building the plant in exchange for stable rates.

[19] Absent the Commission ordering an imprudence adjustment in the eleventh prudence audit case, case no. ER-2023-0277, Evergy West will recover 98% of its FAC costs in the last prudence period where the actual cost incurred were 166% of the FAC costs billed through permanent rates.

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Q. Has the maturing of the energy markets of the regional transmission organizations ("RTO") changed resource planning for load-serving entities such as Evergy West?

A. Yes, but if balancing customer cost and risk is considered, it has not changed materially. Reliance on the energy market is an additional resource choice to meet customers' load requirements.[20] Because the RTOs assure reliable power for its load serving members as a whole, reliance on the spot market becomes an option for RTO's members that serve customers. This option, like other resource options has benefits, *e.g.* assurance that there will be energy, and risks, *e.g.* market prices can be volatile, that should be analyzed before being chosen as part of a utility's resource plan.

Q. What about resource planning has not changed?

A. The objective of resource planning for investor-owned utilities that are members of RTOs is still the same as it was before joining the RTO – to provide the public with energy services that are safe, reliable, and efficient at just and reasonable rates. As I describe in my whitepaper, *Resource Planning of a Vertically Integrated Utility in an RTO World*, attached to this testimony as schedule LMM-D-4, a prudent utility "does not cede to the RTO the electric utility's responsibility of providing its customers reliable service at a reasonable rate."[21] It is the RTO's responsibility to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices <u>on behalf of all its members</u>. It is the utility's responsibility to provide its customers with safe and adequate service at rates that are just and reasonable.

[20] Building to "beat the market" becomes another option.
[21] Pg. 1.

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Q. Is Chapter 22 still relevant?

A. Yes. Chapter 22 is still relevant and applicable. The development of data specific to the utility, the required analysis of that data, and the consideration of risk and uncertainty as prescribed in Chapter 22 are best practices for long-term planning in every industry. Resource planning without consideration of this data is incomplete and imprudent.

In addition, Chapter 22 requires utility management to make the decisions, not the regulators. The size of Chapter 22 is due to the complexity of factors that should be considered and the type of analysis, *e.g.* risk and uncertainty analysis, that should be conducted in prudent planning.

Finally, Chapter 22 contains a provision for the utility to request a waiver or variance from rules 20 CSR 4240-22.030 through 20 CSR 4240-22.080.[22] If a utility believes that any part of these rules is no longer applicable, it can ask the Commission to waive the rule. Very few waivers have been requested in the last 20 years but all that have been requested have been granted.

Q. Does that mean that the preferred plan in a utility's resource planning filing that meets the rule requirements is prudent?

A. No, it does not. The Commission explicitly states in Chapter 22:

> Consistency with an acknowledged preferred resource plan or resource acquisition strategy does not create a rebuttable presumption of prudence and shall not be considered to be dispositive of the issue.[23]

Resource planning is a modeling exercise meant to inform decision making. Like any modeling exercise, the results of a model are only as good as the data put in the model. Likewise, resource planning, as with any modeling exercise, the input data can be manipulated to give a desired answer.

[22] 20 CSR 240-22.080(13).
[23] 20 CSR 240-22.080(17).

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Q. Is total reliance on an RTO for energy an option?

A. Theoretically, yes.[24] But it is an extreme option that would subject the member to the full volatility risk of the market and require other members to have capacity greater than their loads. Generation resources are hedges or "insurance" against price volatility in the SPP market. The better the generation resources match the load, the lesser the price volatility risk.

Q. Would you explain how having generation is a hedge against volatility in the market?

A. I will explain with a simple example with three utilities. In this example hour, each utility has an energy requirement of 100 MWh. In the example hour, the market price is $45/MWh. Because the load requirement is the same for all three utilities, the energy market cost of $4,500 is the same for all three utilities ($45/MWh x 100 MWh).

The generation resources of these three utilities are all different as shown in Table 3 below.

Table 3
Generation Resources

Utility	A	B	C
Available Generation			
Plant 1			
MWh	50	50	50
Variable Cost/MWh	$20	$20	$45
Plant 2			
MWh	100	50	
Variable Cost per MWh	$40	$45	

[24] Theoretically, a utility could enter into capacity only contracts to meet its resource adequacy requirement. Again, this is a simplistic explanation.

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Utility A generates more energy than its customers need. It has two plants with variable costs of $20/MWh and $40/MWh that it has bid into the market at those prices.

Utility B also has two resources. These combined resources can generate 100 MWh thus covering its customers' energy needs. It has bid these two resources into the market at their variable costs of $20/MWh and $45/MWh.

Utility C only has one resource and that resource can only generate enough to cover half of its load. Utility C bids it into the market at its variable cost of $45/MWh.

Because all the plants are bid into the market at or below the market price of $45/MWh, the RTO dispatches all the plants to meet its load. Table 4 shows the calculation of the revenues and costs for each of the utilities.

Table 4
Example RTO Energy Market Variable Cost to Meet Load

Utility	A	B	C
Plant 1			
MWh Produced	50	50	50
Revenue Received	($2,250)	($2,250)	($2,250)
Variable Cost ($/MWh)	$20	$20	$45
Variable Cost Incurred	$1,000	$1,000	$2,250
Plant 2			
MWh Produced	100	50	
Revenue Received	($4,500)	($2,250)	
Variable Cost ($/MWh)	$40	$45	
Variable Cost Incurred	$4,000	$2,250	
Total			
MWh Produced	150	100	50
Revenue Received	($6,750)	($4,500)	($2,250)
Variable Cost Incurred	$5,000	$3,250	$2,250

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The revenue received is the MWh produced multiplied by the market price of $45/MWh. Utility A's plants generate 150 MWh so it receives revenue of $6,750 (150 MWh x $45/MWh). Its variable costs are $5,000 ((50 MWh x $20/MWh) + (100 MWh x $40/MWh)). Utility B's plants generate 100 MWh so it receives $4,500 ($45/MWh x 100 MWh) in revenue for that generation. Its variable costs are $3,250 ((50 MWh x $20/MWh) + (50 MWh x $45/MWh)). Utility C's plant generated 50 MWh so it received $2,250 (50 MWh x $45/MWh). Its variable cost is also $2,250 (50 MWh x $45/MWh).

The net market cost is the energy market cost minus the revenues received for the generation plus the variable cost incurred for that generation. Table 5 shows the net market cost for each of these utilities for this hour. The net market cost per MWh is the net market cost divided by the energy requirement of 100 MWh.

Table 5
Example Net Market Cost @ $45/MWh

Utility	A	B	C
Energy Market Cost	$4,500	$4,500	$4,500
Revenue Received	($6,750)	($4,500)	($2,250)
Variable Cost Incurred	$5,000	$3,250	$2,250
Net Market Cost	$2,750	$3,250	$4,500
Net Market Cost per MWh	$27.50	$32.50	$45.00

The net market cost for Utility A, that had generation above its customers' energy need, is the lowest of the three. It paid the market price of $45/MWh for every MWh its customers needed (100 MWh). It also received $45/MWh for every MWh its generation provided the RTO (150 MWh). Because it had generation above the needs of its customers and the variable costs of these plants were below the market price, its generation provided net revenues that offset the energy market price and resulted in a realized net market price of $27.50/MWh ($2,750/100 MWh) – well

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below the RTO energy market price of $45/MWh. The first 100 MWh of generation offset its load cost. The next 50 MWh of generation provided revenue greater than variable cost (profit) that was used to offset the variable cost of the first 100 MWh. Utility A's generation was a good hedge against market prices because of its low variable cost and it could generate in excess of its customers' energy needs.

The net market price of $32.50/MWh for Utility B, that had enough generation to cover its customers' energy needs, was below the energy market price of $45/MWh too. This was because one of its plants had a variable cost of $20/MWh; well below the market price. The net revenues from this plant reduced the net market price. Because Utility B had generation equal to the energy needs of its customers, it had a hedge against market prices. When market prices are above $45/MWh, it provides a greater hedge. When the market prices are lower than $45/MWh, then Utility B can obtain energy cheaper than its marginal price to generate energy itself. Its units are a hedge against market prices greater than $45/MWh.

The net market price of $45/MWh for Utility C is the same as the energy market price. It had generation that it offered into the market but the variable cost of that unit was the same as the market price. Therefore, there were no revenues in excess of the cost to run the plant.

Q. If the market price was higher than $45/MWh, would this plant be a hedge against market prices for Utility C?

A. Yes. But this generation is only a hedge for 50 MWh of its customers' needs. Its customers' energy needs above 50 MWh would be left at the whims of the market.

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Q. Are there benefits to relying on the energy market to meet customers' energy needs?

A. A utility that does not have cost-effective resources that can meet its customers energy requirements, has two choices; (1) enter into a bilateral contract for capacity and energy from a utility that has excess generation, or (2) enter into a bilateral contract for capacity on and rely on the energy market. The obvious benefit to both of these is that there is no expenditure of the utility's capital to build a resource. However, due to the existence of an energy market, the provider of a bilateral contract for energy would most likely want to price the energy above what it believes it could get from the market. The detriments are the risk of the bilateral contract price being above what the utility would pay in the market or, in the case of relying on the energy market, the risk of volatile market prices.

Q. Why are market prices volatile prices?

A The market prices are driven by supply and demand. When there is a surplus of resources across the RTO, there is excess supply and energy prices are likely to be low. However, as resources tighten up and older low-cost resources are retired, the market prices will increase. On a shorter-term basis, the large amount of zero-variable cost, fluctuating renewable energy results in swings in market prices as the saturation of non-dispatchable resources in the RTO increases. Similarly, when the marginal unit is a natural gas plant, the price of natural gas sets the variable cost. When the cost of natural gas is volatile so is the market price.

Also, as experienced during extreme winter weather in the past four years, restrictions on fuel supply at times of high demand leads to extreme market prices and very high-cost resources being called upon. These are the characteristics and risks of relying on market energy that should be included in any evaluation of market energy as a resource.

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Q. What would be the results if your example used a market price of $90/MWh?

A. Table 6 shows the net market cost when the market price is $90/MWh.[25]

Table 6
Example Market Price @ $90/MWh

Utility	A	B	C
Energy Market Cost	$9,000	$9,000	$9,000
Revenue Received	($13,500)	($9,000)	($4,500)
Variable Cost Incurred	$5,000	$3,250	$2,250
Net Market Cost	$500	$3,250	$6,750
Net Market Cost per MWh	$5.00	$32.50	$67.50

As demonstrated in this scenario, Utility A with excess generation does very well when market prices are high as the revenues generated from the sale of energy almost covers all of the variable cost too. However, this lower net market cost will be offset by higher base rates that include the cost of excess generation plant.

The net market cost of Utility B is the same as it was when market price was $45/MWh. Because it has enough generation to cover its customers' energy needs, the net market cost is the variable cost of its generation. It has hedged its customers' total load while not increasing base rates to recover cost of generation that is not needed.

Because Utility C has a hedge for half of its load, its net market cost of $67.50/MWh is below the market cost of $90/MWh but more than double Utility B's net market cost of $32.50/MWh.

Q. What would happen if the market prices for energy were lower? For example, what would be the results if your example used a market price of $18/MWh?

A. Table 6 shows the results when the market price is $18/MWh.[26]

[25] The workpaper for table 6 is attached as Schedule LMM-D-6.
[26] The workpaper for table 7 is attached as Schedule LMM-D-6.

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Table 7
Example Net Market Cost @ $18/MWh

Utility	A	B	C
Energy Market Cost	$1,800	$1,800	$1,800
Revenue Received	$0	$0	$0
Variable Cost Incurred	$0	$0	$0
Net Market Cost	$1,800	$1,800	$1,800
Net Market Cost per MWh	$18.00	$18.00	$18.00

None of the plants of these three utilities were dispatched because they were bid in above the market price. The net market cost in this example is $18/MWh for all three utilities. In this hour, it is least cost to purchase from the market than it would have been to generate to meet the customers' energy needs. This is a benefit of belonging to an RTO regardless of how much generation a utility owns. Members get the benefit of other utilities' low-cost energy.

Q. Looking at the results from your examples, is having excess generation the most prudent decision?

A. Not necessarily. Of the three utilities, the net market price of Utilities A and C are volatile. However, because Utility A and B have generation to cover their loads, there is a cap on the net market cost of their variable costs. Utility C's cap is whatever the market price is.

My examples looked at only energy market costs. Each generation resource also has fixed costs that were not included in determining cost to the customer. Of the three utilities, Utility A, which has the greatest hedge with net market prices ranging between $5/MWh and $25.50/MWh, would have the greatest fixed cost because it has the most generation. Utility C would have the least fixed cost because it has the least amount of generation. But it has enormous market risk. Across these three hours its net market price ranged from $18/MWh to $67.50/MWh. Utility B, that has

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generation enough to meet its load, has a full hedge against the market and some fixed cost. Its net market cost in hours that it has generation dispatched equal to load will be its variable cost of $35/MWh for the revenues it generates will be the same as the cost for energy. If the market price is less than its variable cost, then the cost will be below $35/MWh. It is the most prudent if its resources are cost-effect and efficient.

Q. What is Evergy West's position regarding the importance of having generation resources?

A. It is Evergy West's position that reliance on the energy market for energy to meet customers' needs exposes customers to a volatile market.

Q. What support do you have for the previous answer?

A. There have been three Evergy West witnesses in recent cases before this Commission that have provided Evergy West's position on the importance of having generation that support OPC's position that reliance on the energy market is imprudent. In case no. EA-2023-0291 ("the *Dogwood* case"), Mr. John J Reed was hired by Evergy West to offer testimony regarding Evergy West's application for Commission approval to acquire a portion of the Dogwood Energy Facility. In that case Mr. Reed directly acknowledge the risks involved in buying energy off the RTO energy market:

> Energy prices in the wholesale market can be volatile and increase the risk of high costs for power purchases to meet load.[27]

Mr. Reed also outlined three ways that electric utilities could meet their customer's energy needs:

> There are various resource strategies by which the utility can meet customers' needs in a cost-effective manner with acceptable risks. One strategy is for utilities to own resources that provide services to their customers, which provides more control over and certainty of

[27] EA-2023-0291, Reed direct testimony, pg. 7.

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> deliverability for meeting customers' needs. This approach also limits exposure to adverse pricing in wholesale electricity markets as the services are effectively self-provided through ownership.
>
> An alternative is to meet these needs through bilateral contracts with pre-determined pricing for energy, capacity and ancillary services. This approach also typically provides a hedge against adverse pricing in wholesale markets but is generally a shorter-term solution and thus is subject to adverse pricing in subsequent rounds of contracting. A third alternative is to rely on broader wholesale market mechanisms to meet the needs of customers. This approach imposes the most price and resource sufficiency risk on the utility.[28]

As I described earlier in this testimony, because Evergy West has a FAC, "this price and resource sufficiency risk" testified to by Mr. Reed is not on Evergy West, but rather, is transferred to Evergy West's customers through the 95/5 sharing mechanism.

Q. Who is the second Evergy West witness that provides Evergy West position for how the load requirements of its customers should be met?

A. Evergy West also offered the testimony in the *Dogwood* case of Ms. Kayla Messamore, its Vice President of Strategy and Long-Term Planning.[29] Ms. Messamore presented a nearly perfect recitation of the risks and problems associated with the Company's current heavy reliance on the SPP energy market to meet its customers' load requirements.

To begin with, Ms. Messamore clearly articulated that "EMW has near- and long-term needs for physical capacity, physical energy, and a hedge against the SPP energy market."[30] (emphasis added). With regard to Evergy West's need for energy, Ms. Messamore explained:

[28] *Id*., pg. 12.
[29] EA-2023-0291, Direct testimony of Kayla Messamore, pg. 1.
[30] *Id.*, pg. 3.

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> [M]arket capacity like the capacity EMW purchases from Evergy Metro only includes mutually agreed upon market energy (or no energy at all), which doesn't provide a long term energy hedge. As a result, the amount of capacity currently covered by these market capacity purchases (240 MW in 2026) represents an incremental need for energy available on the EMW system to meet customer needs. This need for energy can, and has, been met by the wholesale energy market, but this dependence on the energy market can create risk if it is covering a large portion of customer needs for the long-term.[31]

(Emphasis added).

It is at this point that it becomes necessary to remember that Evergy West has been "dependent" on the energy market for *at least* 26% of its energy needs since 2012 as I testified in my direct testimony in case no. EO-2023-0277.[32] And that this amount has since grown to 56% as of the Company's latest resource plan filing.[33] This is the whole basis of the reason that the sharing mechanism needs to change. Evergy West has already "created risk" by "covering a large portion of customer needs" over a very "long term."

Ms. Messamore's testimony becomes even more important when she turns to the question of hedging against market energy prices. To "hedge" is "to use two compensating or offsetting transactions to ensure a position of breaking even; esp., to make advance arrangements to safeguard oneself from loss on an investment, speculation, or bet, as when a buyer of commodities insures against unfavorable price changes by buying in advance at a fixed rate for later delivery."[34] In her testimony in the *Dogwood* case, Ms. Messamore was asked this question: "In prior

[31] *Id.*, pg. 11 – 12.
[32] EO-2024-0277, OPC witness Lena M. Mantle Direct, pg. 12.
[33] 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.
[34] BLACK'S LAW DICTIONARY 869 (11th ed. 2019).

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testimony, Staff implies that there is not a need for energy, but rather a need for a hedge against market energy prices. Do you agree with this perspective?" She responded: "No. These two needs are not mutually exclusive and EMW has a need for both."[35] (emphasis added). She then went on to elaborate:

> In addition, a strategy of relying on wholesale capacity and energy does not provide a hedge for EMW to mitigate its exposure to energy prices. As I will describe in more detail later in this testimony, a large portion of EMW capacity consists of inefficient, high heat rate natural gas turbines which operate very infrequently, as Company Witness Carlson explains. EMW leans on the more economic wholesale market to provide energy when these units aren't dispatched due to being "out of the money". Effectively, this results in EMW being a price taker any time the wholesale market is cheaper than the operating costs of its natural gas turbines, which is a significant portion of the time.
> [. . .]
> In the same way, some of EMW's market capacity contracts also make it a price taker because those contracts do not include corresponding energy. The capacity contracts that do include an energy option are only set at mutually agreeable market prices at the time of transaction. That is the need for an energy hedge which Staff references and which is very real for EMW customers.[36]

(Emphasis added).

It is clear from this excerpt is that Ms. Messamore admitted in the *Dogwood* case that Evergy West (1) cannot currently meet its customers' energy needs with its own generation in a profitable manner for a significant portion of the time, and (2) this means that Evergy West is in critical need of a hedge against the SPP energy market.

The "hedge" that Ms. Messamore refers to in her testimony from the *Dogwood* case is the "insurance" that the OPC is arguing the Company failed to

[35] EA-2023-0291, Direct Testimony of Kayla Messamore, pg. 12.
[36] *Id.*, pg. 12 - 13.

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acquire because it has an FAC with a 95/5 sharing mechanism, thus making Evergy West's actions imprudent. In further support, please consider Ms. Messamore's own words as explication:

> Q: What does it mean to need a hedge?
>
> A: A need for a hedge simply means that you do not have sufficient control or certainty around your future outcomes, based on your specific risk tolerance, and so you want to find some way to improve that control/certainty. As Company Witness Reed describes, insurance is an example of a hedge in that it does come with a cost (insurance premium), but the purpose of it is to give you greater stability and security in your future costs. In general, if you do not end up using your health insurance (e.g., because you did not have any major medical issues), you are better off overall. Would it have been nice to know that you were not going to use the insurance so you could save yourself paying the premium cost? Yes. Would it have been possible for you to know that in advance? No. If something serious had happened, would you have been very glad you had insurance? Yes.[37]

This is identical to what I said earlier regarding how Evergy West would have acted had it not had an FAC sharing mechanism. Because Evergy West has an FAC with a 95/5 sharing mechanism reducing its risk of cost recovery, the Company has decided to act imprudently by not acquiring this necessary insurance (*i.e.* generation necessary to hedge against the SPP energy market prices) for decades.

Q. What impact will Evergy West's acquisition of 22% of the Dogwood combined cycle have on its resource position?

A. **_____

_____

_____

[37] *Id.*, pg. 14.

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_____

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_____ **[38] Its acquisition of a portion of Dogwood does not resolve Evergy West's dependency upon other electric utilities for capacity.[39]

Based on the actual generation from June 2021 through November 2022,[40] Evergy West's 22% of the Dogwood plant would have only increased its generation of energy in that same time period by 8%.[41] While the acquisition of a portion of the Dogwood plant is a step in the right direction, Evergy West is still largely dependent upon the energy market to meet its customers' energy needs.

Q. Who is the third Evergy Missouri witness that has provided testimony that supports OPC's position in this case?

A. The third witness is Mr. Darin Ives, Evergy West's Vice President of Regulatory Affairs. Mr. Ives provided direct testimony in case no. EO-2023-0277 that agrees with my position when he stated:

> Market purchases can play an important role in a prudent resource mix, <u>but on their own are not a plan but rather are akin to playing Lotto with customers energy supply</u>.[42]

(Emphasis added).

Mr. Ives is right. Evergy West's decision to rely on the SPP energy market to supply a large portion of its customers' energy needs is indeed equivalent to Evergy West

[38] From workpaper "MOW ECAA Plan – Excel" provided by Evergy West in Case No. EO-2023-0213, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2023 Integrated Resource Plan Annual Update Filing*
[39] Currently Evergy West has capacity contracts with Evergy Metro and Evergy Kansas.
[40] Evergy West's response to OPC data request 2005 in case no. EA-2023-0291.
[41] Total of owned and PPA generation.
[42] EO-2023-0277, *In the Matter of the Eleventh Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Evergy Missouri West, Inc. d/b/a Evergy Missouri West,* Direct testimony of Darrin R. Ives, pg. 14.

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playing the lotto with customers' money. This was imprudent, as explained by the OPC's witness Dr. Geoff Marke in his surrebuttal testimony in that same case:

> Every decision commits us to some course of action that, by definition, eliminates acting on other alternatives. Placing a bet on the market means we are doubling-down on luck and we are not committing to some other tangible resource that can generate off-system sales. Luck is not a prudent resource. We can't control luck. Therefore relying on the lottery cannot be considered a reasonable course of action.[43]

Q. What information did you consider when developing your recommended sharing mechanism of 75/25?

A. It is obvious that requiring Evergy West to absorb only five percent of the difference between actual cost incurred and the amount of fuel included in revenue requirement is not enough of an incentive for Evergy West to provide a hedge or insurance against volatile market prices for its customers. To make a determination of a more appropriate incentive mechanism, I reviewed the Commission's *Report and Order* in the case where the Commission first granted Aquila an FAC.[44] Not surprisingly, in this case Aquila asked for a 100 percent pass through of costs to customers. However, the Commission found that after-the-fact prudence reviews were insufficient to assure Aquila would take reasonable steps to keep its fuel and purchased power costs down[45] since Aquila would incur no risk of financial loss if it failed to prudently manage its FAC costs.[46]

[43] EO-2023-0277, Surrebuttal testimony of Dr. Geoff Marke, pg. 9.
[44] ER-2007-0004, *In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P Increasing Electric Rates for the services provided to Customers in the Aquila Networks – MPS and Aquila Networks – L&P Service Areas,* attached as Schedule LMM-D-7.
[45] ER-2007-0004, *Report and Order*, page 54.
[46] ER-2007-0004, *Concurring Opinion of Chairman Jeff Davis*, attached as Schedule LMM-D-8, pages 5-6.

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A group of intervenors in the case[47] proposed a 50/50 sharing of costs above those in base rates.[48] The Commission concluded that a 50/50 sharing mechanism did not keep with the legislative intent of Section 386.266.5(1)[49] which requires the FAC to be designed to provide the utility with a sufficient opportunity to earn a fair return on equity. The Commission found that "[w]ith a 95% pass-through, [] Aquila will be protected from extreme fluctuations in fuel and purchased power cost, yet retain a significant incentive to take all reasonable actions to keep its fuel and purchased power costs as low as possible, and still have an opportunity to earn a fair return on its investment."[50]

Chairman Jeff Davis further explained in his concurring opinion to the *Report and Order* in ER-2007-0004:[51]

> The other proposals considered by the PSC would have excessively penalized the company for fuel and purchased power costs far beyond its control. This would make it extremely difficult for the company to reinvest in infrastructure and to attract the investment capital necessary to maintain infrastructure and expand generation capacity.

He went on to explain that there was no science in how the Commission determined that 95% of the costs should flow through the FAC when he stated:[52]

> Absent certainty of fuel cost variances, some aspects of rate setting are like rate design in that they are more art that science. Although the parties are to be commended for coming to an agreement on how the process should work, their extreme positions left this commission in the position of having to try [to] develop a FAC mechanism that would be just and reasonable to all parties.

[47] AARP, SIEUA, AG Processing, and Federal Executive Agencies.
[48] Staff recommended an interim energy charge and OPC recommended the Commission approve neither an FAC nor interim energy charge for Aquila.
[49] At the time of the *Report and Order* this was Section 386.266.4(1).
[50] ER-2007-0004, *Report and Order*, page 54.
[51] ER-2007-0004, Concurring Opinion of Chairman Jeff Davis, page 6.
[52] *Id.*, page 7.

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He also provided the following reminder to Aquila.[53]

> Aquila should be very mindful that the majority of this commission took a bold step in awarding Aquila a fuel adjustment mechanism. This commission and the General Assembly will be watching. If Aquila fails to adopt a proper hedging strategy, fails to follow its hedging strategy or abuses the discretion given to it by this commission in any other way, this commissioner will not hesitate to modify or reject Aquila's FAC application in a future proceeding.

Q. Has Evergy West taken advantage of the large pass through of FAC costs by investing in and maintaining infrastructure or expanding generation capacity as Chairman Davis expected?

A. No. The only additional infrastructure added by Evergy West since this report and order was a 153 MW portion of Iatan 2, which was under construction prior to Evergy West receiving an FAC, the Crossroads Energy Facility that Evergy West's parent company tried to sell but could not find a buyer, and the June 2024 purchase of less than a quarter ownership of the Dogwood plant.

Q. Has Evergy West adopted a proper hedging strategy?

A. No. It has neither built generation to hedge its position in the SPP energy market nor adopted a proper fuel cost hedging strategy. OPC witness John Riley discusses Evergy West's fuel cost hedging strategy in his direct testimony.

Q. Has Evergy West abused the discretion given it by the Commission in its *Report and Order* in case no. ER-2007-0004?

A. Yes, it has.

[53] *Id*.

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Q. What should this Commission take from this Report and Order regarding the sharing mechanism of Evergy West's FAC?

A. First, a large carrot has not induced Evergy West to add generation to hedge the energy market costs for its customers. It was granted an FAC where it would recover over 98% of its FAC costs even if costs were 50% greater than what was included in base rates.[54] Evergy West did not reinvest in infrastructure or expand its generation capacity given this generous sharing mechanism.

Second, the setting of the sharing mechanism is an art. When first setting the 95/5 sharing mechanism, the FAC was new in the State of Missouri. No one was sure how the FAC would work or if a 95/5 sharing was an appropriate mechanism. The Commission realized that prudence reviews alone are inefficient at assuring prudency.

Lastly, the Chairman of the Commission when Evergy West's FAC was first approved under Section 386.266 expected that future Commissions would not hesitate to modify or even reject Evergy West's FAC if it did not adopt a proper hedging strategy or abused the discretion given it by the Commission in its FAC.

Q. How did this order inform your decision to recommend a 75/25 sharing of costs?

A. The 95/5 sharing mechanism that the Commission took a bold step in including in Evergy West's FAC has failed to incent Evergy West to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities. It has instead incentivized Evergy West to put more risk on its customers. This is the only incentive mechanism data point available for review and it has shown it is not enough to "improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities" as envisioned by the legislature.[55]

[54] See pages 12 – 13 of the FAC whitepaper attached as Schedule LMM-D-2.
[55] Section 386.266.1.

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Having no other data points to analyze, I accepted as a floor for a sharing mechanism the Commission's finding in its case no. ER-2007-0004 *Report and Order* that a 50/50 sharing would not allow sufficient recovery of prudent fuel and purchased power costs.[56] A sharing mechanism that recovers 75% of cost above base rates from customers and allows Evergy West 25% of savings is a reasonable choice that relieves some of the risk from the customers to Evergy West. This is a conservative move that would allow movement in future rate cases to Evergy West's response to this increase in its share of the risk. If Evergy West responds with cost-effective resources that can efficiently meet its customer's load requirements, then its share can decrease. If Evergy West continues with its current policy of not adding cost-effective resources, then its share can increase.

Q. Could the Commission adopt any other sharing mechanism?

A. Yes. A sharing mechanism of 85%/15% or 80%/20% would also send a signal to Evergy West that it needs to consider the risk it is placing on the customers through its resource planning decisions to rely on the SPP energy market. A sharing of 60% /40% would send a stronger message. As past Chairman Davis explained in his Concurring Opinion, the setting of a sharing mechanism is an art, not a science.[57]

Q. Is it your expectation that this stick would be more effective than the carrot previously provided by the Commission?

A. I do not think of this change in the mechanism to be a stick. A stick would be shutting down Evergy West's FAC. A 75/25 sharing mechanism is more of a baby carrot as opposed to the current massive carrot that Evergy West expects despite the current failure of that carrot to properly motivate the Company to undertake adequate resource planning.

[56] ER-2007-0004, *Report and Order*, page 54.
[57] ER-2007-0004, *Concurring Opinion of Chairman Jeff Davis*, page 7.

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I do believe that moving the sharing mechanism to 75/25 would signal to Evergy West that this Commission will not tolerate continuous imprudent planning that moves all the risk to Evergy West's customers. It would place Every West on notice that an even smaller carrot or perhaps a stick could be in its future if it does not add cost-effective, efficient generation to its fleet.

Q. Has OPC previously raised concerns regarding Evergy West's resource planning process?

A. Yes. OPC raised its concerns regarding Evergy West's resource plan's increased reliance on energy purchased from the SPP market in at least the following cases:

EO-2017-0230	2017 Annual Resource Plan Update
EO-2017-0232	FAC Prudence Review
EO-2018-0045	Contemporary Resource Planning Issue
ER-2018-0146	General Rate Increase Case
ER-2018-0180	FAC Rate Change Case
EO-2018-0269	Evergy West Triennial Resource Planning Compliance filing
ER-2021-0312	General Rate Increase Case
ER-2022-0130	FAC Rate Change Case
EF-2022-0155	Securitization of Storm Uri Costs
EO-2023-0213	2023 Annual Resource Plan Update
EO-2023-0277	FAC Prudence Review

Q. Why has OPC brought this to the Commission so many times?

A. The Commission's general prudence standard is that the utility's conduct should be judged by asking how, based on information available at that time, a reasonable person would have responded. We presented our concerns with Evergy West in every avenue possible so that a reasonable person would respond to the information provided in a prudent manner.

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Q. Would you summarize your recommendation to the Commission regarding the FAC incentive mechanism?

A. I recommend the Commission modify the incentive mechanism in Evergy West's FAC to pass through 75% of the FAC costs incurred above what is included in base rates for recovery from customers. The current FAC sharing mechanism of passing 95% of the difference has not provided an incentive for Evergy West to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities. It does not provide a great enough risk of financial loss for Evergy West to acquire generation to hedge the fuel and purchased power costs for its customers. If anything, the 95/5 sharing mechanism reduces the risk to Evergy West enough that it is comfortable playing the market with its customers' pocketbooks.

Q. To be clear, would your proposed 75/25 sharing mechanism result in Evergy West only recovering 75% of its total incurred FAC costs?

A. No. The sharing mechanism is applied only to the difference between the FAC costs included in base rates and the actual costs incurred. If Evergy West hits that base rate cost exactly it recovers 100% of its incurred cost. If the actual incurred costs are less than what is included in base rates, then Evergy West recovers more than 100% of its FAC costs since it gets to keep 25% of that savings. It is only if the actual costs are greater than what is included in base rates that Evergy West would not recover all of its costs. In this situation, Evergy West would keep all of the revenue included in base rates for FAC costs and bill customers for 75% of the increased costs.

TREATMENT OF CROSSROADS ENERGY CENTER

Q. Would you briefly describe the Crossroads Energy Center?

A. Crossroads Energy Center ("Crossroads") consists of four 75 MW simple-cycle gas-fired combustion turbines ("CTs") located in Clarksdale, Mississippi. Crossroads is the property of the City of Clarksdale, Mississippi. Evergy West neither owns nor

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leases any part of Crossroads; it has a capital lease on the power generated at Crossroads through 2032. Crossroads is in the service territory of Entergy, Inc. ("Entergy"). Entergy is a member of the Mid-Continental Independent System Operator ("MISO"). Evergy West is a member of SPP. Evergy West has a long-term contract for firm transmission to the SPP. Because there is a firm transmission contract, Crossroads is an SPP accredited capacity resource for Evergy West. The transmission contract ends in March 2029.

The Crossroads facility has a long and storied history.[58] In summary, it was built by Aquila Merchant Services, a non-regulated division of Aquila, Inc. in 2002 with the intent of selling energy into a restructured energy market. In March 2007, the plant was transferred to Aquila, Inc. due to the wind-down of Aquila Merchant operations and Crossroads' inability to effectively dispatch power. Prior to its acquisition by Great Plains Energy ("GPE"), Aquila made at least two attempts to find a buyer for Crossroads but did not get a single bid partially due to transmission constraints. GPE transferred this plant that no other entity would buy to Evergy West after acquiring Aquila.

In Case No. ER-2010-0356, the Commission made the following determinations with regard to Crossroads in its *Report and Order*:

> The Commission rejects Staff's adjustment to disallow the recovery of Crossroads in the Company's cost of service and replace it with the cost of two "phantom turbines." The Commission also rejects GMO's inclusion of Crossroads in rate base at its net book value. The Commission determines that given Great Plains' statements to the Securities Exchange Commission shortly before the transfer of the Crossroads unit to the Missouri regulated operations, as well as the arms-length sale of other General Electric combustion turbines by Aquila, that <u>the fair market value of Crossroads at the time of transfer (August 2008) was $61.8 million</u>. Given the subsequent 32

[58] Details can be found in the Commission's Report and Orders in case nos. ER-2010-0356, pages 77 – 100 and ER-2012-0175, pages 52 – 59. These Report and Orders can be found attached to this testimony as Schedules LMM-D-9 and LMM-D-10 respectively.

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> months, the fair market value of Crossroads for purposes of establishing rate base in this case should also reflect 32 months of depreciation on that unit.
>
> The Commission further determines that it is not just and reasonable for GMO customers to pay the excessive cost of transmission from Mississippi and it shall be excluded. Finally, deferred income taxes shall also be an offset to rate base.[59]

Emphasis added.

Q. Did Evergy West ask the Commission to reconsider its decision?

A. Yes. In its next general rate increase case, ER-2012-0175, Evergy West asked the Commission to increase its valuation of Crossroads and include Crossroads transmission costs in its revenue requirement and its FAC.

Q. What was the Commission's response to Evergy West's request?

A. The Commission ordered the same valuation of the plant. Its decision regarding the treatment of transmission cost, found on page 59 of its Report and Order, was:

> Therefore, the Commission concludes that including the Crossroads transmission costs does not support safe and adequate service at just and reasonable rates, and the Commission will deny those costs.

Q. What has changed since this order with regards to Crossroads since the Commission issued its order in case no. ER-2012-0175?

A. Evergy West entered into a firm transmission contract with Entergy prior to when Entergy joined MISO. At the time of the Commission order in case no. ER-2010-0356, Evergy West was paying about $5 million a year for transmission. When Entergy joined MISO,[60] Evergy West began paying MISO transmission costs to

[59] Pg. 100.
[60] December 19, 2013.

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transport the power to Evergy West. Evergy West paid MISO $15.6 million for firm transmission in 2023.[61]

Q. Should the Commission include Crossroads' transmission cost in revenue requirement and the FAC since it has increased so much?

A. No. The Commission in 2010 and 2013 made the determination that it was imprudent to charge customers $5 million for transmission costs to get electricity from a plant in Mississippi to the Kansas City area. If $5 million was imprudent, spending over three times that amount does not make the decision to acquire a plant over 500 miles away a prudent investment for Evergy West's customers.

Q. Is the special protection scheme that the Commission discussed in its Report and Order in case no. ER-2010-0356 still in effect for Crossroads?

A. Yes. There are two transmission lines serving Crossroads. If one of the lines were to trip, the other one could handle 3 of the 4 turbines at full load. As such, a Special Protection System was installed to ramp one of the turbines down should the second line coming from Crossroads become overloaded.

Q. Does the Crossroads plant provide value to Evergy West's customers?

A. The same value that it did when the Commission issued its orders in case nos. ER-2010-0356 and ER-2012-0175. It provides 300 MW of desperately needed capacity for Evergy West. In 2023, the Crossroads facility generated 208,365 MWh or 4.4% of Evergy West's total generation in 2023.

[61] Evergy West response to OPC data request 8039.

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Q. What amount of Crossroads transmission cost did Evergy West include in its revenue requirement in this case?

A. Evergy West's witness Cody VandeVelde, in his workpapers provided in this case, shows a MISO transmission revenue requirement request amount of **_____ ** In response to OPC data request 8040, Evergy West Senior Regulatory Analyst Ila R. Aspey states that **_____** was included in Evergy West's proposed FAC base calculation for Crossroads transmission costs. Table 7 below shows the actual Crossroads transmission costs incurred, the amount included in revenue requirement request for Crossroads transmission, and the amount of Crossroads transmission that was included in the calculation of the FAC base factor.

Table 7
Crossroad Transmission Cost

2023 Actual Cost of Transmission	$15,593,008
Revenue Requirement Request	**_____ **
FAC Base Factor	**_____ **

Removing the cost of Crossroads transmission would reduce Evergy West requested revenue requirement by **_____ ** and its FAC base by **_____ **

Q. Should the same cost be used for the revenue requirement and the FAC base factor?

A. Yes, the amount included in the FAC base factor should be the same as the amounts included in the revenue requirement used to set base rates in the case or there is a mismatch from the start. I discuss the importance of consistency between the amounts used in the FAC base factor calculation and the revenue requirement on pages 13 through 15 of my whitepaper attached as Schedule LMM-D-2.

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Q. What is your recommendation regarding the treatment of costs of the Crossroads facility?

A. I recommend the Commission continue the rate base treatment of the Crossroads plant as it ordered in case no. ER-2012-0175 and to not include in revenue requirement or Evergy West's FAC the cost of transmitting electricity from the Crossroads facility in Clarksdale, Mississippi to Evergy West's customers in Missouri.

Q. Does this conclude your direct testimony?

A. Yes.

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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 direct 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

Subscribed and sworn to me this 27th day of June 2024.

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

Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2027.