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Lena M. Mantle
Rebuttal Testimony
File Nos. EO-2022-0040 & EO-2022-0193

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Case No.:	EO-2022-0040 and EO-2022-0193

REBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NOS. EO-2022-0040 AND EO-2022-0193

** **
Denotes Confidential information that has been redacted

May 13, 2022

PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financial Order the Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	)))))	Case No. EO-2022-0040
In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	))))))	Case No. EO-2022-0193

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 rebuttal 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 13th day of May 2022.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
TIFFANY HILDEBRAND
My Commission Expires
August 8, 2023
Cole County
Commission #15637121

Tiffany Hildebrand
Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2023.

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

LENA M. MANTLE

THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NOS. EO-2022-0040 & EO-2022-0193

<u>INTRODUCTION</u>

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 is the purpose of your rebuttal testimony?

A. I explain how The Empire District Electric Company's ("Empire") imprudent resource planning to beat the Southwest Power Pool ("SPP") market contributed to it incurring over $200 million in costs to meet its customers' load requirements during Storm Uri in February of 2021. I then recommend that the Commission not allow Empire to recover all of its fuel and purchased power costs that it attributes to Storm Uri because of its imprudent planning and because it did not use the option of controlled curtailment during Storm Uri to reduce costs. To give an understanding of the magnitude of Empire's Storm Uri energy costs, Empire's total energy costs for February 2020 were **____________ **

I recommend that the Commission not allow the five percent portion of the fuel and purchased power costs Empire incurred during February 2021 that the Commission has stated is the appropriate incentive for Empire to efficiently manage its fuel and purchased power costs to be recovered from its customers either through securitization or customer rates.

Also, I respond to Aaron J. Doll's direct testimony[1] that retiring Asbury before it was fully depreciated was in the best interest of Empire's customers. I explain that Empire undervalued Asbury as a generating resource during events such as Storm Uri where the ability to reliably generate electricity on demand is crucial.

Q. What amount of the fuel and purchased power costs Empire is seeking to securitize are you recommending that the Commission authorize it to securitize?

A. I recommend that, rather than the $193,402,198 for February 2021 it seeks, the Commission allow Empire to securitize $120,046,768. The calculation of this amount is shown and explained on Schedule LMM-R-1. This amount may change marginally when I better understand the SPP resettlement amounts that were incurred/returned after February 2021.

Q. What are your experience, education, and other qualifications for testifying on these matters?

A. 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, natural gas, and water cases before the Commission on behalf of the OPC. I am a Registered Professional Engineer in the state of Missouri.

Prior to being employed by 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. Attached as Schedule

[1] EO-2022-0193, page 3.

LMM-R-6 is a brief summary of my experience with the OPC and Staff, and a list of the Commission cases in which I filed testimony, Commission rulemakings in which I participated, and Commission reports in rate cases to which I contributed as Staff.

Q. What is your experience in electric utility resource planning, in particular the resource planning of Missouri investor-owned utilities?

A. When I was employed by the Commission, I was a part of a team that, at the request of the Commission, researched the resource planning practices of the electric utilities in the late 1980s and developed the Commission's Chapter 22 Electric Utility Resource Planning rules that became effective June 12, 1993. During the remainder of my time at the Commission until my retirement in 2012, I reviewed every electric utility resource planning filing before this Commission. Before my retirement from the Commission I also supervised the revision of Chapter 22 that became effective in 2010. I have continued my involvement with the resource plans of the electric utilities since my employment at the OPC in August 2014.

Q. What has the Commission said about the purpose of resource planning?

A. According to the Commission's electric utility resource planning rule 20 CSR 4240-22.010(2):

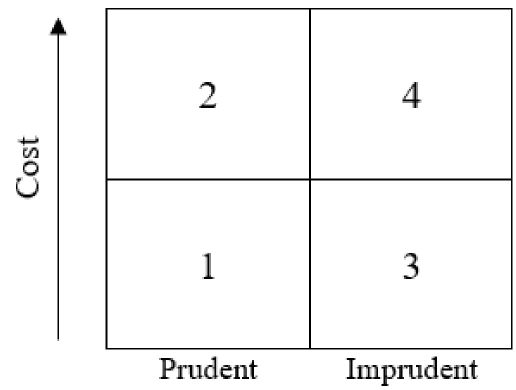
> The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. Empire is charged with providing safe and adequate service at just and reasonable rates.

<u>Prudence</u>

Q. What is your understanding of the relationship between prudence and costs?

A. Figure 1 below depicts the realm of possibilities regarding prudence/imprudence and cost.

Figure 1: Relationship Between Prudence and Costs



Boxes 1 and 2 represent prudent decisions. Box 1 is the ideal - a prudent decision with low costs. While one of the objectives of a prudent decision is low cost, in reality, prudent decisions can sometimes result in increased cost. This is what Box 2 in the diagram illustrates.

Boxes 3 and 4 represent imprudent decisions. Box 3 is a decision that imprudent but does not result in increased costs. Box 4 is a costly, imprudent decision.

Q. What does this relationship between prudence and costs have to do with Empire's Storm Uri purchased power and fuel costs?

A. Empire's resource planning decisions have been imprudent. Prior to Storm Uri, customers did not see an increased cost due to the implementation of the imprudent decisions. In the figure above, the resource planning decisions were in Box 3. Storm Uri put extreme stress on Empire's generation resources. Extreme stress exposes resource portfolio weaknesses, and tests the robustness of the resources to reliably meet load at a just and reasonable cost. The extreme costs Empire incurred exposed the weaknesses of its portfolio which it designed to beat the SPP market, instead of meet the electricity needs of its customers. Storm Uri moved Empire's imprudence from Box 3 with low cost into Box 4 with extreme cost.

Q. Were not the fuel and purchased power costs that Empire incurred due to Storm Uri beyond Empire's control?

A. Yes and no. In the short-term, yes, the fuel and purchased power costs Empire incurred in February 2021 were out of its control. This is one of the risks for which the Commission has rewarded Empire with a return for assuming for years.

However, much of the extraordinary costs Empire incurred because of Storm Uri were the consequence of imprudent, long-term Empire decisions with respect to its generation resources, and the magnitude of the fuel and purchased power costs Empire incurred for February 2021 is a direct result of Empire's implementation of these imprudent decisions. Customers should not be required to pay for the cost consequences of these bad decisions for the next 13 years.

Q. How do you know that Empire's long-term decisions with respect to its generation resources are imprudent?

A. When times are good and market prices are low, just about any resource that provides revenues that offset the cost of meeting load is good. However, a resource planning process that results in resources that can reliably provide sufficient electricity at a reasonable cost 8,760 hours of the year, that is at all times, to match the level required by its customers will mitigate the costs the utility incurs in extreme events like the one Empire experienced in February 2021.

Empire's SPP load cost in February 2021 was **____________** For electricity generated by its generation resources, Empire only earned revenues from SPP of **__________ **.[2] This significant difference demonstrates that Empire did not have adequate generation resources to meet its customers' needs in February 2021.

[2] These are the values at the end of February 2021. Subsequent settlements by SPP were done. At the time of the writing of this testimony, I did not know the impact of these settlements on cost of load or revenue received for generation.

Q. Are you saying that Empire should have generating resources to satisfy its customers' load at all times that include all extreme events?

A. No. There is no way to accurately plan for all extreme circumstances. Adding generation resources should be a balance between cost and reliability. While economics is important, so is looking at the probability customers will be without energy. Empire has made the assumption in its resource planning that because it is a member of SPP, its customers will always have energy available to them, i.e. the loss of load probability is zero because Empire can always get energy from SPP. Storm Uri showed that this incorrect assumption can lead to extreme costs.

Q. In your opinion, if Empire had taken into account both economics and loss of load probability into account in its resource planning process, would Empire had incurred such a great cost during Storm Uri?

A. No. While there may have been some forced outages or derates of some of its resources, the high market prices paid by SPP for generation during Storm Uri would have resulted in a margin large enough to not only cover the load costs but also the increased fuel costs.

Q. How does prudent resource planning manifest itself for a utility in a regional transmission organization like the SPP?

A. Prudent resource planning, for an electric utility with a priority on reliably meeting its customers' energy needs at a low-cost, results in a balancing of regional transmission organization ("RTO") energy market load costs with the revenues from its generation resources. There are times when the RTO costs are greater than the RTO revenues, but they are balanced by the times when the RTO revenues are greater than the RTO costs. A prudent utility treats the RTO as an additional resource for energy and shoulders the combined responsibility of providing reliable service at a reasonable rate to its customers.

This is discussed further in the whitepaper titled, "Resource Planning of a Vertically Integrated Utility in the RTO World" that is attached to this testimony as Schedule LMM-R-2.

Q. What is the difference between energy and capacity?

A. Capacity is the maximum output an electricity generator can physically produce, measured in megawatts ("MW"). Energy is the amount of electricity a generator produces over a defined period of time. For example, a generator with a capacity of 100 MW that runs at full capacity for 10 hours generates 1,000 MWh (100 MW * 10 hours = 1,000 MWh) of energy.

While having enough capacity is essential to having enough energy to meet customers' load requirements, having enough capacity does not necessarily ensure that energy will be available when it is needed. Empire had capacity. The problem was that capacity did not equate to energy when it was needed by Empire's customers due to Empire's long-term resource planning decisions.

Q. Did all of Missouri's investor-owned electric utilities experience the same extreme excess of load costs over revenues from Storm Uri?

A. No. Evergy Metro, which has an excess of generation resources actually generated enough revenues during this time period to cover its load costs, the fuel costs of its generation, and an extra $58.2 million of revenue. Its sister utility, Evergy West, is dependent upon capacity-only purchased power contracts to meet its SPP resource adequacy requirements and relies on the SPP market for energy. Like Empire, Evergy West incurred extraordinary fuel and purchased power costs during Storm Uri that far exceeded its revenues, and it is currently requesting securitization of approximately $300 million costs in Case No. EF-2022-0155.

The other investor-owned electric utility in Missouri, Union Electric Company d/b/a Ameren Missouri, a member of the Midcontinent Independent System Operator RTO, also incurred purchased power and fuel costs greater than

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its revenues, but the difference was not extraordinary. Ameren Missouri passed its February 2021 fuel and purchased power costs to its customers through its FAC absorbing the 5% of the costs. In my opinion, had Ameren Missouri's Callaway Energy Center been operational during Storm Uri, Ameren Missouri would have had sufficient revenues that they would have exceeded its fuel and purchased power costs and resulted in it flowing 95% of the excess to its customers through its FAC.

Empire's Resource Planning

Q. Would you please elaborate on your opinion of why Empire's resource planning has been imprudent?

A. Empire's resource planning objective has shifted from providing energy that safely and reliably serve its customers' energy needs at a just and reasonable rates to maximizing its revenues from the SPP energy market and relying on energy from other members of the SPP to meet Empire's customers' energy requirements.

The Commission acknowledged the risk to customers of a utility investing in generation and relying on the revenues from those investments to exceed their costs to ratepayers in its recent order in Ameren Missouri's resource planning docket when it stated:

> the Commission shares Staff's concern (Concern C) that adding large amounts of renewable generation that are not required to meet MISO resource adequacy requirements or Missouri statutory or rule requirements, including providing safe and adequate service, may place an undue level of risk on ratepayers based on the speculation that market revenues will exceed the overall cost of the assets. Ameren Missouri inherently benefits its shareholders by investing in renewable energy while seeking a return on those investments through future rates. However, that same investment may shift risk to ratepayers that market revenues from the investments may not exceed the cost of the investments.[3]

[3] EO-2021-0021, *In the Matter of Union Electric Company d/b/a Ameren Missouri's 2020 Utility Resource Filing Pursuant to 20 CSR 4240 – Chapter 22*, Order Regarding 2020 Integrated Resource Plan, page 4.

This is the choice that Empire made. Empire has based its resource planning decisions on beating the market - investments that allow its shareholders to earn a return on investments with the prospect of possible future revenues exceeding the cost of the investments. It ceded its responsibility for providing reliable provision of energy to the SPP energy market at unknown and potentially volatile prices.[4]

Q. Why do you assert that Empire has changed its resource objective to beating the market instead of reliably meeting its customers' needs?

A. Empire retired the only coal resource that it independently owned and operated after it sunk a substantial investment into environmental equipment based on resource plan modeling and 14 years prior to its retirement date on the justification that the resource plan model showed it was "uneconomic" to keep Asbury operational. Empire witness Aaron Doll illustrates this mindset in his direct testimony in Case No. EO-2022-0193. His testimony is replete with references to the economics of the Asbury plant yet he does not speak to the impact of the retirement of Asbury on the provision of reliable service to Empire's customers.

In addition, Empire has built three wind projects based on its analysis that the wind projects will generate revenues for customers that are greater than the cost of the projects in the long-term. While customers are facing the market risk of obtaining revenues to cover costs, Empire's shareholders are enjoying a return on its investment.

Another, more subtle indication is that Empire has renamed its resource planning from "Integrated Resource Planning" to "Generation Fleet Savings Analysis."

[4] Because Empire has a fuel adjustment clause nearly all the fuel and purchased power costs are borne by customers eliminating much of the risk to shareholders of unanticipated increases in costs.

Q. Did Empire find any of its other generation resources to be uneconomic?

A. No, but this was because Asbury was the only resource that Empire allowed the resource planning modelling to retire.

Q. Based on your experience, would any of Empire's other resources have been economic if the resource planning modeling would have allowed them to retire?

A. It is my experience that an electric utility can, within certain limitations, make any resource uneconomic or economic based on what inputs it chooses to include in its resource planning models. That said, I have not looked closely at the inputs into the resource planning models Empire relied on to know how Empire may have manipulated the modeling to show Asbury would be uneconomic.

Q. What were Asbury's revenue margins on the SPP market prior to when Empire retired it?

A. According to the *Net Fuel and Purchased Power Reports* Empire provides as a part of its FAC monthly report submissions, Asbury, in the 24 months of September 2017 through August 2019,[5] had a positive margin of $4.2 million meaning it generated revenues in the SPP market $4.2 million more than its variable cost.

Q. Was this margin more than Empire's fixed operations and maintenance costs for Asbury?

A. No.

Q. Does this mean Asbury was uneconomic?

A. It does if the definition is purely monetary economics of the SPP market. However, the Asbury plant carried great value in reducing the price variability and reliability

[5] Empire submitted its plan to SPP to retire Asbury in September 2019. At that time it began burning its coal inventory in preparation of its retirement resulting in fuel costs greater than the revenues from SPP at that time.

risk to customers. This plant moved from being a valuable asset to customers to a drain on their wallets.

Q. How has Empire retiring Asbury impacted Empire's customers' bills?

A. For more than 17 months after Empire ceased generation, customers not only paid for the Asbury plant and a return on the plant, they also paid for fixed operation and maintenance costs to run the plant and a non-existent 60 days' burn pile of coal. Now Empire is asking the Commission to require customers to pay the stranded costs plus a return on that cost for a generation plant that provides neither energy nor reliability to them.

Q. Did Empire consider the impact on its ability to provide reliable service to its customers when it decided to retire Asbury?

A. No. The only study that was conducted on the reliability impact of retiring Asbury was the SPP analysis conducted when Empire submitted its request for retirement of Asbury.[6] I am aware of no studies on the impact of retiring Asbury on Empire's ability to reliably provide energy to its customers.

Q. Can you estimate the price variability and reliability value of Asbury?

A. Yes. Had Asbury not been retired, it would have created revenues of over $71.4 million in February 2021 if it had been available and generating electricity.[7] This was the price variability and reliability value of Asbury. This is eerily close to the difference between load cost and SPP revenues for Empire's system in February 2021.

[6] Response to OPC data request 8113, Case ER-2021-0312 attached as Schedule LMM-R-3.
[7] North Fork node prices, summer capacity rate for Asbury of 194 MW and Staff's fuel cost for Asbury in rate case ER-2021-0312.

Q. Does Empire have any resources that consistently have negative margins, i.e., cost more than the revenues they generate?

A. Yes. Empire's wind purchased power agreements ("PPAs"), Elk River and Meridian Way, consistently cost Empire's rate payers over $1 million a month. In response to OPC data request 8044 in case EA-2019-0010, Empire provided that these PPAs had lost over $55 million from 2015 through 2018. Most of these losses were paid for by the customers as 95% of the net of these costs flow through Empire's FAC.

Q. How can wind resources have a negative margin?

A. Empire's wind PPA contracts require the wind turbines to generate electricity whenever the wind is blowing regardless of the SPP market price. Low market prices have resulted in negative margins for Empire's wind PPAs in every month except when market prices skyrocketed in February 2021.

Q. Has Empire tried to exit these uneconomic PPAs?

A. To my knowledge, Empire has not engaged in any activity to find a way to end these PPAs before their contracted end dates.

Q. How did Empire support building its Neosho Ridge, North Fork Ridge and Kings Point wind projects?

A. In case EA-2018-0092, when Empire first introduced its plan to build new wind resources, it presented an analysis that, over 30 years, they will generate revenues for customers that are greater than their cost. In that case its resource modeling witness, Empire witness James McMahon, in his direct testimony, consistently emphasized that the critical criteria for adding resources was economics. He did mention that the wind projects could be used to provide "reliable" service but did not emphasize the "reliability" aspect because wind generation can only be relied on when the wind is blowing.

This is supported by Empire's agreement to a "market price protection plan" where Empire agreed, if the revenues generated are not greater than the cost over the first ten years, to cover a portion of the difference.

<u>Prudent Resource Portfolios</u>

Q. What is a prudent resource portfolio for a vertically-integrated electric utility?

A. A good resource portfolio is one that contains diverse types of generation resources, each with its own strengths and weaknesses that is chosen to meet the unique load demands of the utility's customers at all times while also minimizing the risk of high utility bills and loss of service. When determining the acquisition, continuation, or retirement of any resource, the availability of fuel and the dispatchability of the resource, along with meeting environmental regulations needs to be considered. No one type of resource on its own can meet all of the requirements of a utility's load. However, a diverse portfolio of resources will.

Q. What do you mean by dispatchability of the resource?

A. Dispatchability refers to being able to depend on a resource to provide electricity when the electricity is needed. Fossil fuel units are units that can be relied on to generate electricity when needed, i.e. dispatched. When it is not needed to generate electricity, the plant does not generate. Renewable generation is not completely dispatchable. It cannot be counted on to provide electricity upon customer demands. If the headwater is available (hydro), the wind blowing, or the sun shining, they can provide electricity. However, when the headwater is not available, the wind is not blowing and the sun is not shining, these resources cannot generate electricity.

Q. Empire witness Aaron Doll provided a list of Empire's resources used to meet SPP's 2021 resource adequacy standards in his direct testimony.[8] Is this not a diverse set of resource types?

A. It is diverse with respect to the fuel sources and types of generation plant. However, it is limited because the only generation plants that Empire has operational control of are its natural gas turbines and that control is limited by the availability of natural gas.

Q. Have you reviewed Empire's resources in the past?

A. Yes. I have been reviewing Empire's generation resources and resource planning process for the last 30 years.

Q. Is Empire's current planning process consistent with the process it used before Algonquin acquired it?

A. No. Prior to when Algonquin acquired Empire on January 1, 2017, Empire's resource acquisition and retirement decisions were based on what it needed to safely and reliably meet its customers' loads every hour of the year at the least cost. Empire had a diverse mix of resources. It was the sole owner of the Asbury plant that, had for decades, reliably provided inexpensive energy, and after considerable resource planning analysis to determine the least cost of meeting its customers' needs while meeting environmental requirements, added equipment that resulted in a more efficient plant that met all environmental requirements and extended its engineering life. It typically had more than a 30 days' supply of coal on the Asbury site. The long expected life of this coal plant and its ability to reliably generate electricity made it a valuable part of Empire's generation resource portfolio for 49 years, and that is why Empire made extensive costly investments in that plant in 2008 and 2014 to extend its life to 2035.

[8] EO-2022-0040, page 3.

To supplement its solely-owned coal-fired generation, Empire acquired minority ownership of three other coal-fired, baseload generating plants. These baseload plants provided, and still provide, electricity at a low variable cost to Empire's customers on a continuous basis. These coal plants too typically have a 30 days' supply of fuel on hand. Yet, because Empire is a minority owner, Empire has no control of dispatch decisions, or operations and maintenance, at these plants.

Prior to the SPP integrated energy market, and initially after the beginning of the market, these coal-fired generating plants generated as much electricity as possible, with planned outages for maintenance scheduled when demand for electricity was expected to be low. Large expenditures to increase efficiency and extend the life of these coal plants were considered to be natural extensions of the ability to reliably maintain these low-cost, reliable sources of electricity. Sixty to ninety days' of coal inventory was stored on-site allowing these plants to continue to generate electricity, even when there were problems with the delivery of coal, which provided an added reliability benefit to these plants.

The advent of the SPP market and the addition of large amounts of wind generation has changed how utilities utilize their generation resources. The ability to dispatch and run coal generation has often been overshadowed by the often-narrow margin of earnings on the energy market.

Q. What are Empire's other generating resources?

A. Empire owns and maintains two natural gas combined cycle plants. It is the sole owner of one plant and a majority owner of the other. These efficient, natural gas generating plants have been workhorses for Empire, both before and after the advent of the SPP energy market. When natural gas prices are low, these plants can generate electricity at a cost that rivals the cost of electricity from coal plants without the long ramp-up times of the coal plants. These plants, like coal plants, are available when needed, with the exception of when they are shut down for maintenance or have an outage for an unforeseen reason.

However, these combined cycle plants are dependent upon the gas pipelines to provide natural gas when energy is needed. Empire has firm transportation contracts for a supply of natural gas. However, as was experienced in Storm Uri, these firm contracts do not necessarily result in natural gas being physically available when it is needed the most.

Empire also owns some simple cycle combustion turbines that were relatively inexpensive to build, but are more costly to run. Some of these combustion turbines are also able to run on fuel oil which is stored onsite. While typically these plants do not generate much electricity, their availability to be dispatched and their dual fuel capabilities made them very valuable during Storm Uri.

Q. Has Empire experienced gas supply problems to any of its generating plants since February 2021?

A. **____

____ **[9]

Q. What about renewable generating resources?

A. Renewables are good supplemental energy sources. Their biggest drawback is they cannot be counted on to produce electricity at any given time. Their availability is dependent up the flow of the river and whether or not the wind is blowing or the sun is shining. Empire's oldest renewable resources are its Ozark Beach hydro units. These four small hydroelectric units of 4 MW each have been generating energy since 1913 and continue to be included in Empire's resource portfolio. When headwaters are adequate, they are available on demand and because their variable cost is near zero, they are always profitable for Empire.

Empire's first wind-resources are purchased power agreements ("PPAs"). Empire pays the owner of the wind project a set amount for each megawatt hour

[9] BFMR-2022-0456, Liberty Empire District January 2022 Net Fuel and Purchased Power report.

generated regardless of the price SPP is offering. When Empire entered into these purchased power contracts, its resource planning analysis showed that what Empire would pay for the wind generation would be competitive with other sources of generation over the lifetime of the purchased power agreement. These resources were not intended to increase the reliability of Empire's system, but instead to supplement the electricity generated with other resources. Since the advent of the SPP market, Empire has consistently lost money on these PPAs, since the PPAs require electricity be produced when the wind is blowing, regardless of whether selling the electricity they generate is profitable to Empire or not.

For the wind projects that Empire recently acquired, there is no fuel cost, making them Empire's lowest cost electricity generating resource. The problem is that these are not resources that can always be relied upon to generate electricity to meet customers' needs. When the wind is not blowing, there is no electricity from these resources, regardless of the need of Empire's customers. These projects have the potential to provide revenue, but cannot be relied on during times of need, because the wind may not be blowing.

Q. How do the resources shown in Aaron Doll's direct testimony compare to Empire's preferred plan in Empire's previous two resource planning filings?

A. Table 2 provides a comparison of the Empire resources submitted to SPP for its Summer 2021 rating and the planned resources for Summer 2021 from Empire's preferred plans in its last two triennial resource plan compliance filings.[10]

[10] With the acquisition of Empire by Algonquin, Empire now calls its resource planning process "Generation Fleet Savings Analysis" or GFSA.

Table 2
Empire Resources

Resource	Doll Testimony	2016 RP EO-2016-0223	2019 RP EO-2019-0049
Riverton CTs	29	**__	__**
Stateline CT	93	**__	___**
Energy Center CTs	245	**___	___**
Ozark (hydro)	16	**__	__**
Riverton 12 CC	254	**___	___**
Stateline CC	300	**___	___**
Asbury	0	**___	_**
Iatan	192	**___	___**
Plum Pt (owned)	50	**__	__**
Plum Pt (PPA)	50	**__	__**
Elk River Wind	33	**___	__**
Meridian Way Wind	17	**__	__**
New Wind	0	**_	___**
North Fork Ridge	7.5	**_	_**
Neosho Ridge	15.1	**_	_**
Kings Point	7.5	**_	_**
New Solar	0	**_	_**
Total Capacity MW	1309	1472	1595

This comparison shows that the resources that were accredited by SPP in 2021 for Empire were considerably less than the resources in Empire's preferred plans of the last two resource plan compliance filings. The biggest difference between Empire's 2016 and 2019 preferred plans was a reduction of 194 MW due to the retirement of the Asbury coal plant, anticipated increases in capacity of Empire natural gas resources of 109 MW and the addition of 181 MW of accredited wind capacity.[11] A comparison of Empire's 2019 preferred plan and its 2021 SPP resource adequacy is that the 2021 SPP accredited capacity for Empire's natural gas units is 124 MW

[11] Algonquin acquired Empire between these two triennial resource plan filings.

lower and the wind accredited capacity[12] was 165 MW lower than the 2019 preferred plan Empire filed with the Commission.

Q. What do the changes to Empire's preferred resource plan have to do with Empire's ability to control its costs in February 2021?

A. It has everything to do with Empire's ability to control its costs in February 2021. Empire's ability to control costs was directly tied to the resources it had available to generate electricity to sell into the SPP market in February 2021.

Empire had retired on its books the only coal plant that it controlled on March 1, 2020,[13] 15 years before the end of its engineering life, because the margin this coal plant was making in the SPP market was not covering its fixed operation and maintenance costs. Now Empire has no baseload coal generation resources that it has control over, meaning that Empire does not participate in the decisions regarding hardening these plants for operation in cold temperatures or preparing the plants for operation during extreme cold. These plants had their generation limited for a variety of reasons during Storm Uri, none of which were under the control of Empire.

Empire did have control over the operation and maintenance of its combined cycle natural gas plants, but that control is only meaningful when the natural gas sources are reliable. While Empire had paid for firm transportation to its natural gas plants, this firm transportation became not so firm during Storm Uri, limiting the electricity these natural gas-fired plants produced.

Empire's simple cycle combustion turbines with dual fuel capabilities were its only reliable generating sources during Storm Uri. The dual fuel capabilities allowed Empire to operate these resources during Storm Uri when there were

[12] The manufacturer capacities of the wind resources was the same between Empire's 2019 preferred plan and 2021. The difference is due to Empire's overestimation of the amount of capacity SPP would accredit these resources.

[13] It actually ceased operating on December 12, 2019 after it used all of its burnable coal inventory.

constraints on the provision of natural gas. However, its Riverton 10 combustion turbine was **____ ________________________________ **

Fortunately, for Empire's customers, Ozark Beach was able to generate greater than anticipated electricity from these small hydro units in February 2021 **__________________________**[14] However, this amount of energy cannot be depended upon in the resource planning process.

Empire's 100 MW PPA wind project, Meridian Way was **________ ____ ________** Its other 150 MW PPA wind project, Elk River, **___ ____** during Storm Uri.[15]

Q. Did Empires' three new wind projects – Neosho Ridge, North Fork Ridge, and Kings Point – provide generation in February 2021?

A. Yes. Neosho Ridge and Kings Point were in various phases of construction during February 2021 that limited their generation. North Fork was in commercial operation[16] **____ ____ ____ **

Q. Were the revenues from these wind projects used to offset load costs?

A. No. Because these three wind projects were not in rate base yet, the limited revenues from these wind projects did not offset customer load costs. The revenues were retained by Empire.

[14] BFMR-2021-1076, Liberty – Empire District: February 2021 Electric Net Fuel and Purchased Power Report attached as Schedule LMM-R-4.
[15] *Id.*
[16] ER-2021-0312, OPC data request 8055.

Q. How much margin did each of Empire's resources generate for its customers in February 2021?

A. Table 1 shows the margins in February 2021 from each of Empire's generation resources.[17] Negative numbers indicate costs were greater than revenues for Empire's **

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Resource Planning

Q. Did the Commission approve Empire's resource plans?

A. No. Chapter 22 Electric Utility Resource Planning rule 20 CSR 4240-22.010 (1) specifically states:

[17] BFMR-2021-1076, Empire February 2021 FAC monthly report, 02-2021 fac data – 09-2020 – 02-2021 (2).xlsx.

> Compliance with these rules shall not be construed to result in commission approval of the utility's resource plans, resource acquisition strategies, or investment decisions.

The Commission, in the last Empire triennial resource planning case, Case No. EO-2019-0049, did not approve Empire's resource plan, but, instead, approved the remedies to alleged deficiencies and concerns of parties to the case.[18] In Empire's resource planning case, Case No. EO-2016-0223, prior to the EO-2019-0049 case, the Commission stated in its order that it found the filing was in substantial compliance *with the requirements of Chapter 22*.[19]

Q. What is the purpose of the Commission's electric utility resource planning compliance filings?

A. Chapter 22 contains minimum standards regarding *the data* the electric utilities should review and *the methodologies* to be used for analyzing the data. The decisions regarding resource acquisition strategies are the decisions of utility management. Chapter 22 does not take away management's control of the resource planning process or the implementation of a resource plan, but requires electric utilities to look at a minimum set of data and to include an analysis of risk to inform the decision makers in their resource planning processes.

Q. Are you aware if the results of Empire's resource planning processes ever show any of its resource plans cannot meet the requirements of its customers?

A. No. Given how Empire conducts its resource planning process, its models will never show customer energy load not being met.

Q. Why not?

A. In its resource planning analysis, Empire inputs an almost unlimited amount of energy available to meet Empire's customers' energy loads from SPP at a price

[18] Page 3.
[19] Page 2.

consistent with its normalized market prices. Sensitivity analyses are run, but only with prices typically 25% higher and 25% lower than predicted. Storm Uri's prices were more than 100 times higher than the average SPP market price in 2020.

Q. Is it a reasonable assumption that Empire could purchase however much energy its customers need in any given hour?

A. It may be a reasonable assumption for "normal" circumstances, but it is not reasonable to assume that there should ever be a need for unlimited amounts of energy or that unlimited amounts will always be available.

Q. Is an analysis that only varies prices by 25% a true test of sensitivity?

A. No, it is not. A true test of sensitivity would be extreme market prices and generation constraints to see how any given resource plan performs in extreme circumstance with limited resources available from SPP and extremely high prices. Similarly analysis should also be conducted on the impact of negative market prices on market revenues – especially if the resource is being added because the utility believes its market revenues will be greater than its costs.

Q. Do Empire's analyses based on unlimited SPP energy availability and projected prices give an accurate portrayal of how Empire's resources meet Empire's energy loads?

A. No. How well Empire's resources meet Empire's customers energy loads can only be seen in model runs that do not include access to SPP energy. I am not advocating that this be how Empire determines its resource plans. It is good resource planning to allow SPP to be a resource. However, a comparison of a stand-alone resource plan and a resource plan that allows unfettered access to SPP will give an idea of the risk Empire is placing on its customers.

Q. Has Empire done such an analysis?

A. Not to my knowledge.

SPP Resource Adequacy Is Not Adequate for Empire Customers

Q. Empire witness Aaron Doll testifies that Empire was compliant with the resource adequacy requirements of the Southwest Power Pool.[20] What is that requirement?

A. The SPP requires its load serving entities ("LSE") to have a reserve marge of 12%. Meaning, to meet SPP's resource adequacy requirement, Empire needs to have accredited capacity[21] 112% greater than its forecasted peak load. SPP limits renewables to a portion of the manufactured rated capacity due to their intermittent resources. SPP puts no requirements on its LSEs to meet the hourly requirements of the LSE's customers. SPP has no requirements for cost-effectiveness, or safety or reliability for each LSE's customers. The only requirement is that the accredited capacity equal at least 112% of the LSE's forecasted load.

Q. Is meeting SPP's resource adequacy requirement an indication of the prudency of Empire's resources for meeting the electricity needs of Empire's customers?

A. No. It is not an indicator of the prudency of the resource plans of Empire to meet its customers' load requirements. It only indicates that Empire met the requirements placed on it by the SPP that, if all the generation is available at time of the peak load, Empire has enough resources to meet two hours of load requirements of its customers – the summer peak load hour and the winter peak load hour. It indicates that SPP believes that *SPP* can meet the load requirements of its members if all its members meet its resource adequacy standards given the

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[20] Direct testimony, page 8.
[21] Capacity is defined by SPP as amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station or system is rated by the manufacturer. (https://www.spp.org/glossary/?term=Capacity) To account for the intermittency of renewables, the capacity rating for these resources used by SPP for resource adequacy is a portion of the manufacturer rated capacity.

diversity of its members' resources. It indicates nothing with regard to the ability of any given member meeting its particular customers' load requirements.

Q. Is not one of the purposes of the SPP to provide safe, reliable electricity at a reasonable cost to Empire's customers?

A. No. According to the SPP's website, "We work together with our members and other stakeholders to ensure electricity is delivered reliably and affordably <u>to the millions of people living in our multistate service territory.</u>" (Emphasis added). SPP's resource adequacy requirement revolves around SPP being able to serve all of its members—not just Empire. The responsibility of providing reliable and safe electricity at a reasonable cost to Empire's customers is Empire's alone.

Q. Does the SPP acknowledge that meeting the SPP resource adequacy requirement does not necessarily mean that there will be energy available in the SPP market to a particular utility <u>when that utility</u> needs it?

A. Yes. In its 2021 SPP Resource Adequacy Report, the SPP states:

> Attachment AA of the Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (Tariff) requires a Load Responsible Entity (LRE) to maintain adequate capacity to meet its Resource Adequacy Requirement for the upcoming Summer Season. Maintaining appropriate planning reserves ensures that <u>SPP</u> will have sufficient capacity <u>to serve peak demand</u> obligations. (Footnote omitted, emphasis added)[22]

There are a couple of key points in this quote. First is that the objective of the SPP's resource adequacy requirement is for the <u>*SPP*</u> to maintain adequate capacity. It is not to ensure that any one of its Load Responsible Entities (regulated electric utilities) has adequate capacity to meet the energy needs of its customers at a just and reasonable cost. This is the responsibility of the individual electric utility.

[22] Page 1.

Second is that the resource adequacy requirement is set so that the SPP will have significant capacity to serve *peak demand*.[23] Not to provide reliable energy for every hour. Not to minimize outages. Not for Empire. Not for any one LSE. The resource adequacy requirement is to ensure that the SPP can meet the needs of one hour – the peak summer hour.

Q. Why should a utility that is part of a regional transmission organization be concerned about resource adequacy if it satisfies the regional transmission organization's reserve margin requirement for it?

A. While the customers of utilities that are members of regional transmission organizations ("RTOs') are likely to have the energy they need available from the RTO, relying on the market exposes customers to high energy price risk. If a utility has adequate resources, the cost of extreme weather events such as the one which occurred in February 2021 will be significantly lower for those utilities that have adequate resource capacity.

The circumstances surrounding Storm Uri shows that there is a possibility of a RTO being short on energy. An assumption that energy will be available for all members of a RTO at any time is unrealistic. Customers needed energy to heat their homes at a time when SPP required its members to curtail their loads so that its system would not crash. SPP came very close to not having enough generation to supply the need.

[23] Attachment AA to SPP's OATT defines peak hour as "The highest demand including a) transmission losses for energy, b) the projected impacts of Non-Controllable and Non-Dispatchable Behind-The-Meter Generation, and c) the projected impacts of Non-Controllable and Non-Dispatchable Demand Response Programs measured over a one clock hour period."

Q. Is it reasonable to assume that a RTO may not have the energy its members need in the near future?

A. Yes. The Electric Reliability Council of Texas (ERCOT) and the Midcontinent Independent System Operator (MISO) in early May 2022 separately expressed concerns about power supply uncertainties in the face of warmer-than-normal temperatures.[24]

Q. How should a utility prepare for such circumstances?

A. By not relying on the market to meet its customers' energy needs, and using the market to supplement owned resources. In the long term, generation resources are hedges in the energy market. Some types of generation are better hedges against market energy availability (dispatchable) than others (intermittent). In the short-term, utilities should prepare its customers for potential curtailment.

Q. How are generation resources hedges?

A. The benefit of any resource in the energy market is the difference between the cost to produce energy and the market price for that energy. If a utility owns its wind resources, the entire revenue provided by the market is a benefit. Whenever owned wind resources are generating and market prices are positive, the wind resources are a hedge against prices regardless of whether the price is high or low. This is the benefit of an owned wind resource.

However, wind resources are only a hedge to market prices when wind is available. When wind is not blowing or when wind turbines freeze up, then wind resources are not hedges against market prices.

Dispatchable resources provide a hedge when the market price is greater than the cost for that resource to produce electricity. The benefit is the difference between the market price and the cost of producing the electricity. When market

[24] https://www.powermag.com/ercot-miso-warn-of-potential-power-supply-shortfalls/

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prices are high and the dispatchable resources are producing electricity, the dispatchable resources are a hedge against market prices because they are able to provide electricity at the time when market prices exceed the cost for that resource to produce electricity. This excess revenue should not be the sole reason for the resource. Having the resource available to offset high market prices should be.

The difference in the value of the resource is the dependability of the source of energy used to create electricity. Dispatchable resources use energy sources that are typically available upon demand. This adds value to these resources. Intermittent resources provide benefits when their energy source—water, wind, or light—is available.

Q. Given the recent time of extreme market prices in February 2021, were both types of resources hedges against market prices?

A. Yes. Every resource that could generate electricity was a hedge against load market prices. However, dispatchable resources with on-site fuel were better hedges because they were more reliable.

Q. Did Empire consider the adequacy of Empire's resources to meet its customers' energy requirements when it decided to retire Asbury?

A. I have not seen any documentation that Empire reviewed the impact of retiring Asbury on its ability to adequately meet its customers' needs. The modeling done by Empire always allowed Empire to purchase energy from the SPP to meet its load. The modeling that was used to justify the retirement of the Asbury plant did not restrict the energy needed to meet its customers' to be from its own resources.

<u>Meaning of a Certificate of Convenience and Necessity</u>

Q. Does granting a Certificate of Convenience and Necessity ("CCN") mean that resources should be built?

A. No. I am not an attorney so I will not speak to the legal aspects of this question. However, I am aware of instances when the Commission issued CCNs for generation and the utility chose to not go forward with construction of the generation. The most recent example would be Union Electric Company's decision not to build a second nuclear plant at Callaway.

<u>5% of FAC costs</u>

Q. Why should the Commission exclude five percent of Empire's extraordinary February 2021 fuel and purchased power costs?

A. There are at least two reasons the Commission should exclude 5% of February 2021 fuel and purchased power costs. First, if the Commission allows Empire to recover this 5%, through securitization or customer rates, then the Commission, in effect, has removed any incentive for Empire to plan for and to efficiently manage extraordinary events that impact its biggest cost. Empire should be on the hook for the 5%.

Secondly, the load cost that Empire is wanting to pass on to its customers is determined by 1) the load market price, and 2) the magnitude of the load. While Empire had no control over the cost that the SPP charged it for load, Empire had control over the other part of the equation – its load.

Q. Would you further explain the reason for the 5% incentive?

A. Prior to the advent of the FAC, electric utilities carried all the risk of such extraordinary events. In exchange for assuming this risk, the Commission allowed electric utilities to earn a return on their investments.

Then in 2005, legislation was passed[25] that allowed the Commission to approve FACs for the electric utilities that would eliminate most of the risk of not being able to recover the fuel costs associated with providing electricity for their customers. The Legislature included language in the statute that allows the Commission to include a provision in a utility's FAC to include an incentive for the electric utility to more efficiently manage its fuel and purchased power costs. The Commission has determined that it was appropriate for utilities, as an incentive to efficiently manage its fuel and purchased power costs, to be at risk for 5% of the cost above what was included in base rates, and be rewarded 5% of the costs below what was included in base rates.[26]

However, I am not aware of any meaningful reduction to the return on equity the Commission authorizes electric utilities due to a decrease in the risk of utilities recovering fuel and purchased power costs since the advent of FACs. The risk of fuel cost fluctuations has essentially been moved from utilities and to their customers without customers seeing a reduction in rates for taking on this risk.

If the Commission allows Empire to recover this cost through securitization, then the returns Empire has been earning since the Commission first authorized it to use a FAC have falsely compensated Empire for an assumed exposure to risk that did not exist.

Q. What was the resource that Empire had available to it that it chose not to use during Storm Uri?

A. Empire could have reduced its customers' usage when prices increased to an unprecedented amount. It could, and should, have initiated controlled service interruptions to reduce its aggregate cost of energy during Storm Uri.

[25] Section 386.266 RSMo.

[26] In the Empire rate case, ER-2019-0374, OPC recommended that the sharing mechanism be adjusted from 5% to 15% as an incentive for Empire to act efficiently. In its *Amended Report and Order* in that case, the Commission determined "that based on the facts in this case, the 95/5 sharing mechanism in Empire's FAC provides the appropriate incentive to properly manage its net energy costs."

Q. But did not Empire curtail its customers' usage during Storm Uri?

A. Yes, but only when the SPP required it to do so. Empire provided the following description of the curtailments in its February 2021 Fuel and Purchased Power report submitted in BFMR-2021-1076 attached as Schedule LMM-R-4:

** ____

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In all other hours during Storm Uri, Empire just assumed that its customers were okay with paying astronomical prices for energy – costs that Empire is now asking its customers to pay over the next 13 years.

Q. Is it your opinion that Empire should have turned off its customers' electricity during a period of extremely cold temperatures before the SPP required it to do so?

A. Yes. It is an opinion that does not come easy. I am not saying that Empire should have turned off electricity for extended amount of time for all of its customers. *Controlled service interruptions*, with information relayed on times and places before the commencement of the interruptions, following the Phase 1 and Phase II guidelines in Empire's Emergency Energy Conservation Plan, could have reduced the cost that is being requested from customers in this case while taking into account the needs of its customers who provide essential health and public services. Empire's tariff sheets that outline its Emergency Energy Conservation Plan[27] are attached to this testimony as Schedule LMM-R-5.

Q. Would not controlled interruptions have inconvenienced Empire's customers?

A. Yes, for an hour a day every other day for a few days. I am confident that customers, had they known the magnitude of the cost Empire was incurring, and

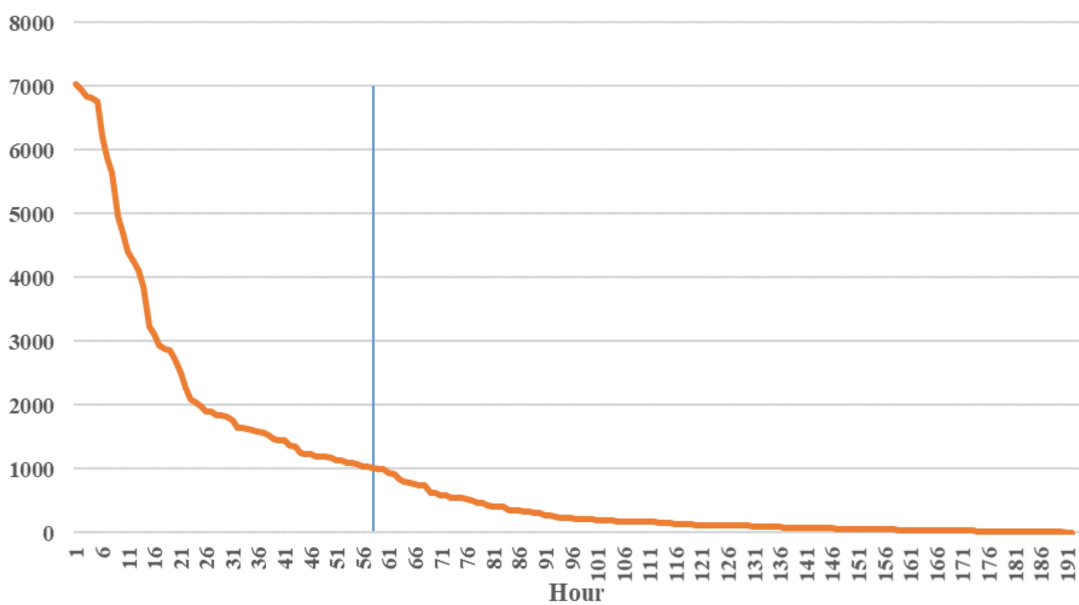
[27] P.S.C. Mo. No. 6, Section 5, Original Sheets 22 and 23.

intending to pass on to them, would have accepted some short-term inconvenience to mitigate paying hundreds of millions of dollars over 13 years.

Q. When should Empire have begun controlled interruptions?

A. I do not know the exact SPP market price or price duration that should have triggered Empire to start interrupting service. However, I reviewed the SPP day ahead 5 minute prices for February 12 through February 19 and I do believe that the prices exceeded the point that customers would have been amenable to controlled service curtailments. The graph below shows the range of the hourly prices[28] at the Empire load node.

Figure 1
Hourly Market Prices at Empire Load Node
February 12 – February 19, 2021
Ranked Highest to Lowest



The highest hourly price during this time period was over $7,000 per

[28] Calculated as the average of the 5-minute prices for that hour.

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MWh.[29] During this time, there were over 24 hours where the price was over $2,000 per MWh and over 58 hours when the price was above $1,000 per MWh.

To get a perspective on how extreme prices were, the peak cost for a kilowatt-hour ("kWh") of energy was over $7.00/kWh. Empire's FAC base rate, which is the normalized fuel and purchased power cost from the last general rate case, is less than three cents a kWh ($0.03/kWh).

To get a comparison to what the SPP market prices were prior to Storm Uri, the average day-ahead market price for 2020 was $17.69/MWh or $0.01769/kWh.[30] Empire's average price for these eight days was $949 per MWh or almost a dollar a kWh.

Therefore, at a minimum, the Commission should not allow Empire cost recovery of the 5% of fuel and purchased power costs that could have flowed through Empire's FAC. While it is theoretically possible to calculate the potential impact of a controlled interruption, many assumptions would have to be made and it would require information that is not available to me at this time.

Q. What has been the treatment of the 5% incentive for other electric utilities in Missouri?

A. Evergy Metro, who had revenues greater than costs in February 2021 kept the 5%. Ameren Missouri who had costs greater than revenues, absorbed the 5%. Evergy West, like Empire is asking for the 5% to be included in its securitization of February 2021 costs.

Q. Does this conclude your direct testimony?

A. Yes.

[29] The highest 5-minute price at the Empire load node was almost $9,600.

[30] 2020 State of the Market Report, SPP Market Monitoring Unit, August 12, 2021, page 1.

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Case No. EO-2022-0040
& EO-2022-0193

Schedule LMM-R-1 to

Lena M. Mantle's

Rebuttal Testimony

has been deemed

"Confidential"

in its entirety

Resource Planning of a Vertically Integrated Utility in the RTO World

A Whitepaper

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May 12, 2022

The purpose of this whitepaper is to provide an overview of the potential impacts of a regional transmission organization ("RTO") energy market on resource planning of vertically integrated electric utilities. It is not a comprehensive thesis on either resource planning or the RTO energy market. In fact, both electric utility resource planning and RTO energy markets are very complicated with numerous interactions. This whitepaper is a simplistic view of both. Any views expressed are my own and not necessarily that of the Missouri Office of the Public Counsel.

Resource Planning of a Vertically Integrated Utility in the RTO World

Introduction

Prudent resource planning for a vertically integrated electric utility places a priority on reliably meeting its customers' needs at a reasonable cost. Resources that achieve this balance of reliability and cost typically result in a balancing of load costs charged by a regional transmission organization ("RTO") and revenues provided by the RTO for energy generation.

There are times when RTO load costs are greater than revenues but these times are balanced by the times that revenues are greater than costs. Prudent resource planning treats the RTO as a supplemental resource and does not cede the responsibility of providing its customers reliable service at a reasonable rate to the RTO.

A measure of the adequacy of resource planning of a vertically integrated utility (load serving entity or "LSE") that is a member of a RTO with an energy market is a comparison of the cost of the load charged the utility by the RTO and the revenues the utility receives from the RTO for generation. However, this comparison of RTO costs and revenues should not be the objective of resource planning. The objective of resource planning should be providing customers with energy services that are safe, reliable, and efficient at just and reasonable rates.

When revenue for generation is near or greater than the cost of the load, this is an indication that the utility can meet the loads of its customers regardless of whether or not it belongs to an RTO. A revenue much larger than the cost is an indication the utility may have overbuilt. While this is sometime necessary due to the bulkiness of adding generation, this continuously occurring over the long-term is an indication the utility overbuilt. Consistently overbuilding results in increased bills for customers to recover the capital costs of the generation and the return on that investment for shareholders. While the excess generation may result in additional RTO revenues, a prudent utility does not gamble the size of customers' bills on beating the RTO market.

Costs consistently greater than the revenues indicates that the utility is relying on the RTO to meet the load requirements of its customers. The utility can still meet the planning capacity requirement of the RTO, either with (1) capacity-only purchased power agreements that do not include the provision of energy to sell into the market, or (2) it maintains its old costly generation resources for the capacity value knowing that the cost of energy generated using these old resources will seldom be in the money in the energy market. The customers of a utility that relies on the RTO for energy subjects its customers to the volatility and uncertainty of the electric market.

When market and fuel costs skyrocket as they did in February 2021, the prudent utility, while incurring high fuel costs, has the resources to generate revenues in the RTO market to offset the load cost and, because the market price is so much greater than the variable cost of the utility, generate some revenue for its customers. Utilities without resources, either due to unavailability or just lack of energy producing resources because they depend on the market, incur high fuel costs for the limited resources that are bid into the market and they do not generate market revenues to fully offset the load costs. Therefore, load costs above revenues generated are indications of inadequate resource planning by utilities.

Load Serving Entities and the RTO Energy Market

RTOs facilitate the sale and purchase of electricity between its members. It has a centralized energy market and its reliability standard is to cost-effectively meet the combined loads of its members not the load of any one member.

Vertically integrated utilities or Load Serving Entities ("LSE") that are members of the RTO, pay the RTO for the hourly[1] load of its customers at a price that is set by the RTO. This cost is independent of the energy provided to the market from generation of the LSE in that hour. For example, if a LSE's load is 1,000 mega-Watts ("MW") it pays the RTO for 1,000 MW regardless of the fact that it, in that same hour, is generating 600 MW, 1,000 MW or 1,200 MW.

In Missouri, this charge by the RTO for load is considered purchased power and the cost flows through the fuel adjustment charge ("FAC") to the LSE's customers.

Generally, LSEs bid a generation resource into the market at a price to cover the variable cost of generating energy from that resource. [2] If the market price is greater than the bid (meaning revenue generated will at least cover the variable cost of generating energy from that resource), then the energy from that resource is sold into the market and the fuel cost to generate that energy is charged to the customer. Revenue from the sale of energy to the RTO is considered off-system sales revenue which is also included in the FAC in Missouri offsetting fuel and purchased power costs. The difference between the hourly market prices offered for generation and the prices charged for the load is a measure of congestion in the market.

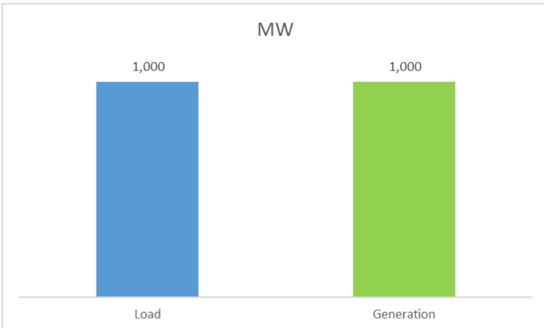
Three scenarios follow demonstrating in simplistic terms, these principles. The following assumptions are made to simplify these scenarios.

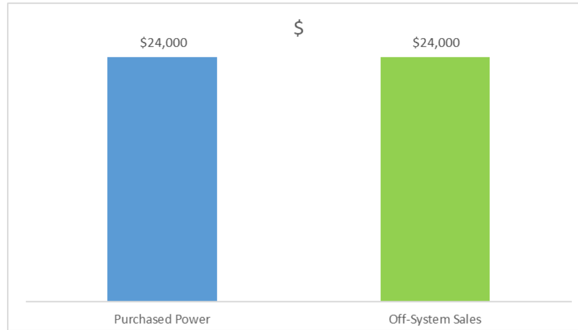
Congestion	$0
Load Charge	$24/MWh
Revenue for Generation	$24/MWh
Generation variable cost	$22/MWh

[1] While this is typically done on a 5 minute basis, for this document, the price interval will be considered hourly which is calculated as the average of the 5 minute prices.

[2] Generation can be self-committed meaning it generates regardless of the market price. The assumption in this document is that none of the generation is self-committed.

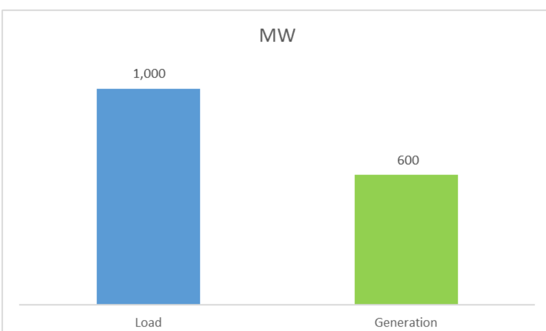
Scenario 1: Load = Generation

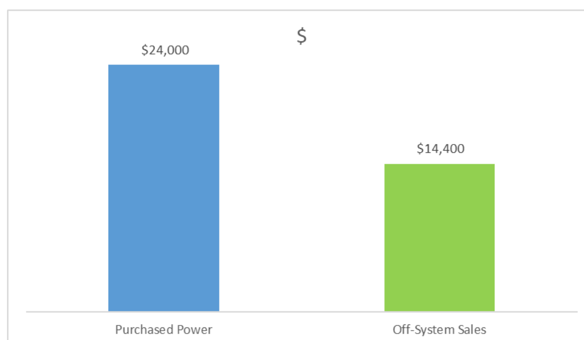




In this scenario, the price paid for the load of 1,000 MW ($24,000) is netted against the revenue provided for the 1,000 MW of generation ($24,000) resulting in no additional cost for the customers for participating in the RTO. The cost for that generation was $22/MW so the customers pay this variable cost of generation of $22,000 just as they would have paid if the utility was not a part of the RTO. The utility earns a return on and of the generation resources.

Scenario 2: Load > Generation





In this scenario, the price paid for the load of $24,000 is netted against the revenue provided for the generation of $14,400 resulting in a cost of $9,600 to customers. The variable cost to customers of the 600 MW of generation at $22/MWh is $13,200. The total cost to the customer of $22,800 is the combined market cost and variable cost.

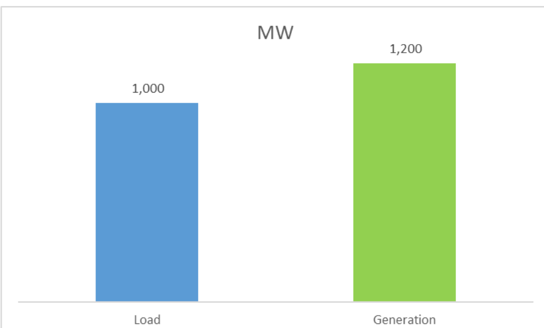
The total cost of not having generation in the market is greater in this scenario than the first scenario. In addition to the increased cost, this LSE relies on the generation of other members of the RTO to meet 400 MW of its customers load requirements.

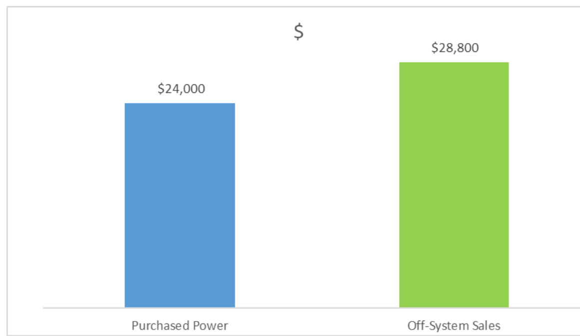
There are generally two reasons why a LSE buys more from the RTO than it generates. First it may be because other members have resources that can generate electricity at a cost lower than the LSE. This is a monetary benefit to customer because buying from the market is cheaper than the fuel costs of the

LSE. There are no reliability concerns since, if the energy cannot be provided by the market, the LSE can generate it but at a higher cost than purchasing through the market. The utility continues to earn a return on and of its generation resources even if the resources variable costs were greater than market price.

The other reason a LSE may buy from the market is that the LSE does not have enough generation resources available that hour to meets its customers' loads thus relying on other utilities to provide energy for its customers. In this instance, the price risk is assumed by customers because the load cost flows through the FAC. There is little to no consequence to the utility because the load cost flows through the FAC. The utility earns a return on and of its limited generation resources.

Scenario 3: Load < Generation





In a RTO market, the generation a LSE can provide to the market is not limited to the load of the utility. In this scenario, the LSE pays the RTO $24,000 for its load and receives $28,800 in revenue for its generation netting $4,800 in revenue. However, the customers must pay the variable cost of for the 1200 MW ($26,400) for the generation. The $4,800 offsets the variable cost resulting in a total cost of $21,600. The cost to customers is lowest in this scenario.

In this scenario, the customers have no reliability risk for the utility has more generation than its customers needed.

Summary of Scenarios

	Load Cost	Resource Rev	Variable Cost	Total Cost
1: Load = Generation	$24,000	$24,000	$22,000	$22,000
2: Load > Generation	$24,000	$14,400	$13,200	$22,800
3: Load <Generation	$24,000	$28,800	$26,400	$21,600

In reality, these scenarios play out for every hour and an LSE may experience all three scenarios in a day. It is rare that a utility supplies the exact amount of energy into the market that it needs. For a well-balanced utility, there will be hours when it supplies more to the market and hours when the market supplies its needs cheaper than if it generated itself.

When looking at these scenarios, a utility could decide that its objective would be to have resources so that the generation would be greater than the load often enough that it would net out any times that load was greater than generation. The fallacy of this objective is that market prices are not static. They fluctuate within every hour. By building to provide energy to the market and not to meet customer loads exposes customers to price risk. If the prices used in the resource planning analysis are accurate, then the customers see the bills estimated in the resource planning process. However, the only thing that is certain about projections is that they will be wrong. This type of planning puts this risk on customers.

Absent in the economics of these three scenarios is the cost of the investments in generation. Resource planning is a balancing of the investment cost for generation and the benefits of both reliability and RTO revenue.

LSE Types

Type 1: Prudent Utility

The resource planning objective of the prudent utility is to meet its customers' loads 8,760 hours of the year at a reasonable cost that minimizes risks and values flexibility across a variety of various futures – some of which include extreme market prices. Its resource planning objective is to be able to provide generation required by its customers every hour at a cost below market prices. To do this all generation resources are considered taking into account uncertainties and risks of each resource (e.g. reliability of natural gas delivery, intermittent availability of renewables, nuclear waste disposal, residual disposal, environmental restrictions). The flexibility of the resource during extreme events (e.g., natural gas prices, market volatility, extreme weather) is also a consideration when choosing a resource. While this utility can meet its customers' needs on a stand-alone basis, it sees value in being a part of a market where it can sell generation when it is not needed by its customers and being able to take advantage of other utilities' diversity of energy resources and loads. This utility does not build to meet the RTO planning reserve margin but meets the RTO planning reserve margin because it builds to meet its customers' needs.

<u>Response to Scenarios:</u>

Scenario 1: Load = Generation

Prudent Utility has the ability to be in this position in every hour of the year. It's rare that it actually occurs but it is possible.

Scenario 2: Load > Generation

Prudent utility will take energy from the market when the price is below its cost of generating more energy or it has a forced outage at one of its generation plants. Reliability for its customers remains high and customers' bills will be reduced when market prices are lower than generation.

Scenario 3: Load < Generation

Prudent utility could find itself in this position at times when its load is low and its generation is available. It does not build with an objective of being in this situation because that results in higher bills due to the increased investment.

Type 2: Market Player Utility

The Market Player Utility planning objective is to beat the market. Its critical assumption in the resource planning process is forecasted market price assumptions although, since it has a FAC, the market player utility will not assume that risk so it is not important to the utility whether or not the price assumptions are correct. That risk will be assumed by the utility's customers. If market prices meet or exceed planning projections, customers' bills are lowered by the market gain; if market prices are lower than projected in the planning, customers' bills are increased.

Reliability of resources to meet customers' energy requirements is not a consideration. Actually customer load is inconsequential to the Market Player Utility. Least-cost in planning is measured by how much revenue the utility forecasts the resources can generate in the market not by how well it meets customers requirements. There is no risk to the utility if forecasted market prices are not realized. Fixed costs plus a return for shareholders are recovered through rates charged customers regardless of whether the resources are in-the-money or not.

Part of the planning process of the market player utility is to make sure that the utility meets RTO planning reserve margin. It is not a natural fallout of the planning process. The RTO is necessary for Market Player Utility's customers to be assured that they have the energy resources they require; the Market Player Utility cedes its responsibility for providing energy to its customers to the RTO.

<u>Response to Scenarios:</u>

Scenario 1: Load = Generation

This scenario occurring for a Market Player Utility in any given hour is a coincidence. It is not planned for. Market Player Utility only adds generation to beat the market, not to assure its customers that it can meet their load requirements. It depends on the RTO market to provide energy for its customers.

Scenario 2: Load > Generation

This scenario occurring for a Market Player Utility in any given hour is a coincidence. While it is not necessarily planned for, the Market Player Utility is not concerned when it occurs. The increased cost of purchasing from the market is covered by its customers through the FAC. The Market Player Utility is hoping that Scenario 3 will happen enough to generate revenues to cover costs incurred in this scenario.

Scenario 3: Load < Generation

This is the scenario that the Market Player Utility is hoping happens. If it does not happen enough to cover the increased costs that occurred in other hours, there is no harm to the utility for the load costs are recovered from the customers through the FAC. Its customers pay not only for the increased cost when this planned for but not realized scenario does not occur, but also the capital cost of and return on additional generation that was built to beat the market.

Type 3: Moocher Utility

Moocher Utility avoids adding owned-generation. It has a short-term view for meeting RTO capacity requirements often relying on other utilities' excess capacity to meet the RTO's requirements. If it enters into purchased power agreements for energy the objective is not to provide energy when its customers need it but to beat the market. The Moocher Utility cedes its responsibility for providing energy to its customers to the RTO relying on the RTO energy market to meet its customers' energy requirements.

Because both market energy costs and purchased power agreement energy cost are included in its FAC, lower than forecasted market prices do not impact Moocher Utility's shareholders but do increase the volatility and magnitude of customers' bills

Response to Scenarios:

Scenario 1: Load = Generation

This scenario occurring for a Moocher Utility in any given hour is an unlikely coincidence.

Scenario 1: Load > Generation

This is the likely scenario for a Moocher Utility in any given hour Its reliance on capacity only purchased power contracts to meet the RTO planning reserve margin means that it is not concerned with providing reliable, low cost energy for its customers. Customers' bills can be volatile due to the fluctuations of the cost of market energy. Because the costs flow through to the customer, there is no consequence to Moocher utility of not having capacity without energy.

Scenario 3: Generation > Load

This scenario rarely happens for the Moocher Utility because it meets the RTO capacity requirements with capacity only purchased power agreements.

Conclusion

Electric utility resource planning in the days before RTO markets centered on obtaining resources that would provide reliable energy at a reasonable cost for customers. RTOs offer valuable additional resources for energy and increased reliability to supplement a utility's resources. However, the energy markets have opened another objective for adding resources – generating revenues. Electric utility shareholders can earn a return on investment with a utility's projected possibility of revenues that, in the long run, are greater than the cost to customers. Earnings to shareholders are a given. A reduction to customers' bills due to market revenues is a possibility. However, even if this possibility does not pan out, shareholders still receive earnings and customers pay the costs.

A utility can also become reliant on RTOs for energy to meet its customers' needs. However, the objective of a RTO is to cost-effectively meet the combined loads of its members and not the load of any one member.

The interplay between a utility and the RTO it belongs to should be considered in resource planning but a resource portfolio should be built for customers not the RTO energy market.

Liberty

Liberty Utilities (The Empire District Electric Company)
Case No. ER-2021-0312
Office Public Counsel Data Request - 8113

Data Request Received: 2021-11-30
Response Date: 2021-12-13
Request No. 8113
Witness/Respondent: Tim Wilson
Submitted by: Lena Mantle, lena.mantle@opc.mo.gov

REQUEST:

Please provide each and every study of the effect of retiring Empire's Asbury plant on the reliability of Empire's resources to meet its customers' electricity needs at all times. If no such studies were completed, please explain in detail why not.

RESPONSE:

At least 6 months prior to retiring Asbury, Empire was required to submit the request for retirement to Southwest Power Pool (SPP) for studies relating to reliability. These studies include a review of the steady state and dynamic impacts directly related to the retirement of the asset as well as identify any upgrades to accommodate the asset retirement from the transmission system. SPP performed these studies, and Empire does not have possession of the studies. SPP, as the independent system operator (ISO), reliability coordinator (RC) and tariff administrator for SPP, is responsible for ensuring reliability, including as it relates to unit retirement and SPP resource adequacy (RA). As a note, Section 7.2 of the SPP Bylaws states that the Regional State Committee (RSC), which is comprised of one designated commissioner from each regulatory commission having jurisdiction over an SPP member, will determine the approach for resource adequacy across the entire region. Empire has consistently used SPP guidelines to determine the necessary capacity levels to meet RA requirements.

Case No. EO-2022-0040
& EO-2022-0193

Schedule LMM-R-4 to

Lena M. Mantle's

Rebuttal Testimony

has been deemed

"Confidential"

in its entirety

CHAPTER IV

EMERGENCY ENERGY CONSERVATION PLAN

A. GENERAL

The purpose of this plan is to define actions that will be taken when an imminent fuel shortage threatens the ability of the Company to continue services which are essential to the health and well being of the Company's Customers.

The Plan will be a two phase plan, with the second phase being implemented in the event Phase I fails to provide adequate reduction in energy consumption. The Plan will be implemented as necessary and in the order shown. Should conditions deteriorate rapidly, Phase II may be implemented before any or all steps in Phase I have been completed.

B. PHASE I

1. Elimination of all non-essential Company consumption.

2. Voluntary elimination of all non-essential lighting, including but not limited to:
   - Homes
   - Stores
   - Educational Institutions
   - Industries
   - Commercial Buildings
   - Street Lighting
   - Outdoor Advertising
   - Parking Lot Lighting

3. A voluntary 20% reduction in consumption for educational institutions, museums, art galleries and historic buildings.

4. Voluntary elimination of all night-time sporting events and other recreational uses.

5. Interruption of service to all Customers served on interruptible rates as provided in the respective rate or contract.

6. Voluntary reduction by industrial Customers which will result in a 20% reduction in energy consumption.

7. Voluntary reduction in the use of home heating equipment and appliances to the lowest use necessary to maintain life support systems.

   In the event the steps implemented in Phase I do not provide adequate reduction in consumption to mitigate the imminent fuel shortage, State and Federal regulatory commissions or other appropriate authority will be requested to authorize The Empire District Electric Company to implement Phase II procedures as they become necessary to preserve the Company's fuel inventory and maintain essential services.

C. PHASE II

1. Mandatory elimination and reduction as outlined in Phase I.

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Service Commission
ER-2019-0374; EN-2021-0038;
YE-2021-0041

2. Mandatory elimination of consumption by all educational institutions, museums, art galleries and historic buildings.

3. Voltage reduction of 5% for all Customers.

4. Rotating two-hour service interruption on selected feeder lines. The System Operator will be responsible for implementing and controlling the interruptions, and, where possible, will avoid interruption of circuits which serve critical needs of the community.

   The Company Energy Curtailment Plan will be reviewed on an annual basis by those responsible for its implementation so as to make any changes which may be either necessary or desirable, and in order to maintain the desired degree of familiarity with the plan.

D. ESSENTIAL SERVICES

The following Customers will be exempt from full compliance with the plan as outlined in Phase II due to the essential nature of the service they provide. Although exempted from the mandatory provision of this plan, such Customers would be expected to cooperate to the fullest extent possible consistent with the continued operation of the essential service for which the Customer is responsible.

1. Any facility whose function is known to the Company to be necessary to the support of life.

   a. Certain hospital services and nursing homes.

   b. Non-hospital facilities which may have iron lung or kidney machines.

2. Any facility whose function is necessary for National, State or local security.

   a. Civil Defense facilities.

   b. Other Governmental activities essential to national defense.

3. Any facility whose function is known to be necessary to provide essential public services.

   a. Police and fire control facilities.

   b. Public utilities - water, telephone, cellular communication, gas, sewage disposal facilities.

   c. Transportation facilities.

   d. Communications media - newspapers, radio and television stations.

   e. Coal mining and related functions.

   f. Petroleum refining and pipeline facilities.

   g. Food processing, storage and distribution facilities.

   h. Medical supply facilities.

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YE-2021-0041

Education and Work Experience Background of

Lena M. Mantle, P.E.

In my position as Senior Analyst for the Office of the Public Counsel ("OPC") I provide analytic and engineering support for the OPC in electric, gas, and water cases before the Commission. I have worked for the OPC since August, 2014.

I retired on December 31, 2012 from the Public Service Commission Staff as the Manager of the Energy Unit. As the Manager of the Energy Unit, I oversaw and coordinated the activities of five sections: Engineering Analysis, Electric and Gas Tariffs, Natural Gas Safety, Economic Analysis, and Energy Analysis sections. These sections were responsible for providing Staff positions before the Commission on all of the electric and gas cases filed at the Commission. This included reviews of fuel adjustment clause filings, resource planning compliance, gas safety reports, customer complaint reviews, territorial agreement reviews, electric safety incidents and the class cost-of-service and rate design for natural gas and electric utilities.

Prior to being the Manager of the Energy Unit, I was the Supervisor of the Engineering Analysis Section of the Energy Department from August, 2001 through June, 2005. In this position, I supervised engineers in a wide variety of engineering analysis including electric utility fuel and purchased power expense estimation for rate cases, generation plant construction audits, review of territorial agreements, and resolution of customer complaints all the while remaining the lead Staff conducting weather normalization in electric cases.

From the beginning of my employment with the Commission in the Research and Planning Department in August, 1983 through August, 2001, I worked in many areas of electric utility regulation. Initially I worked on electric utility class cost-of-service analysis, fuel modeling and what has since become known as demand-side management. As a member of the Research and Planning Department under the direct supervision of Dr. Michael Proctor, I participated in the development of a leading-edge methodology for weather normalizing hourly class energy for rate design cases. I took the lead in developing personal computer programming of this methodology and applying this methodology to weather-normalize electric usage in numerous electric rate cases. I was also a member of the team that assisted in the development of the Missouri Public Service Commission electronic filing and information system ("EFIS").

I received a Bachelor of Science Degree in Industrial Engineering from the University of Missouri, at Columbia, in May, 1983. I am a registered Professional Engineer in the State of Missouri.

Lists of the cases I have filed testimony as an OPC, the Missouri Public Service Commission rules in which I participated in the development of or revision to, and the cases that I provided testimony in follow.

Office of Public Counsel Case Listing

Case	Filing Type	Issue
ER-2021-0312	Direct, Rebuttal	Storm costs, Market Price Protection Mechanism, FAC
GR-2021-0241	Direct, Rebuttal, Surrebuttal	Revenue Normalization Adjustment, Customer Bills
ER-2021-0240	Direct, Rebuttal	FAC, Customer Bills
GR-2021-0108	Direct, Rebuttal, Surrebuttal	Weather Normalization Adjustment mechanism, miscellaneous tariff issues
WR-2020-0240	Direct, Rebuttal, Surrebuttal	Normalized customer usage, revenue stabilization mechanism
EO-2020-0262	Direct	FAC Imprudence
ER-2020-0311	Rebuttal	FAC rate change
ER-2019-0374	Direct, Rebuttal, Surrebuttal	Weather Norm Rider, Fuel Adjustment Clause
ER-2019-0355	Direct, Rebuttal	Fuel Adjustment Clause, Unregulated Competition tariff sheet
EO-2019-0067 & EO-2019-0068	Rebuttal	Prudence of GMO steam auxiliary costs and GMO and KCPL's wind PPAs
EA-2019-0010	Rebuttal, Surrebuttal	Energy Market Prices, Customer Protections
GO-2019-0058 & GO-2019-0059	Direct, Rebuttal	Weather
ER-2018-0145 & ER-2018-0146	Direct, Rebuttal, Surrebuttal	Purchased Power, Customer Bills, Crossroads, Resource Planning
EO-2018-0092	Rebuttal, Surrebuttal	OPC Opposition of Request for Approval of Changes to Resource Plan
WR-2017-0285	Direct, Rebuttal, Surrebuttal	Normalized base usage
GR-2017-0215 & GR-2017-0216	Direct, Rebuttal, Surrebuttal	Energy Efficiency and Low-Income Programs
EO-2017-0065	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause Prudence Review
ER-2016-0285	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2016-0179	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause,
ER-2016-0156	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause, Resource Planning
ER-2016-0023	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
WR-2015-0301	Direct, Rebuttal, Surrebuttal	Revenues, Environmental Cost Recovery Mechanism
ER-2014-0370	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0351	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0258	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
EC-2014-0224	Surrebuttal	Policy, Rate Design

Missouri Public Service Commission Rules

20 CSR 4240-3	Filing Requirements for Electric Utilities (various rules)
20 CSR 4240-14	Utility Promotional Practices
20 CSR 4240-18	Safety Standards
20 CSR 4240-20.015	Electric Utility Affiliate Transactions
20 CSR 4240-20.017	HVAC Services Affiliate Transactions

20 CSR 4240-20.090	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms
20 CSR 4240-20.091	Electric Utility Environmental Cost Recovery Mechanisms
20 CSR 4240-22	Electric Utility Resource Planning
20 CSR 4240-80.015	Steam Heating Utility Affiliate Transactions
20 CSR 4240-80.017	HVAC Services Affiliate Transactions

Missouri Public Service Commission Staff Testimony

Case No.	Filing Type	Issue
ER-2012-0175	Rebuttal, Surrebuttal	Resource Planning Capacity Allocation
ER-2012-0166	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EO-2012-0074	Direct/Rebuttal	Fuel Adjustment Clause Prudence
EO-2011-0390	Rebuttal	Resource Planning Fuel Adjustment Clause
ER-2011-0028	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EU-2012-0027	Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2010-0356	Rebuttal, Surrebuttal	Resource Planning Allocation of Iatan 2
EO-2010-0255	Direct/Rebuttal	
ER-2010-0036	Supplemental Direct, Surrebuttal	Fuel Adjustment Clause
ER-2009-0090	Surrebuttal	Capacity Requirements
ER-2008-0318	Surrebuttal	Fuel Adjustment Clause
ER-2008-0093	Rebuttal, Surrebuttal	Fuel Adjustment Clause Low-Income Program
ER-2007-0004	Direct, Surrebuttal	Resource Planning
GR-2007-0003	Direct	Energy Efficiency Program Cost Recovery
ER-2007-0002	Direct	Demand-Side Program Cost Recovery
ER-2006-0315	Supplemental Direct, Rebuttal	Energy Forecast, Demand-Side Programs Low-Income Programs
ER-2006-0314	Rebuttal	Jurisdictional Allocation Factor
EA-2006-0309	Rebuttal, Surrebuttal	Resource Planning
ER-2005-0436	Direct, Rebuttal, Surrebuttal	Low-Income Programs, Energy Efficiency Programs, Resource Planning
EO-2005-0329	Spontaneous	Demand-Side Programs, Resource Planning
EO-2005-0293	Spontaneous	Demand-Side Programs, Resource Planning
ER-2004-0570	Direct, Rebuttal, Surrebuttal	Reliability Indices, Energy Efficiency Programs Wind Research Program
EF-2003-0465	Rebuttal	Resource Planning
ER-2002-424	Direct	Derivation of Normal Weather
EC-2002-1	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-672	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-299	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EM-2000-369	Direct	Load Research
EM-2000-292	Direct	Load Research

Case No.	Filing Type	Issue
EM-97-515	Direct	Normalization of Net System
ER-97-394, et. al.	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System Energy Audit Tariff
EO-94-174	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
ER-97-81	Direct	Weather Normalization of Class Sales Weather Normalization of Net System TES Tariff
ER-95-279	Direct	Normalization of Net System
ET-95-209	Rebuttal, Surrebuttal	New Construction Pilot Program
EO-94-199	Direct	Normalization of Net System
ER-94-163	Direct	Normalization of Net System
ER-93-37	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-91-74, et. al.	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-90-251	Rebuttal	Promotional Practices Variance
ER-90-138	Direct	Weather Normalization of Net System
ER-90-101	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-85-128, et. al.	Direct	Demand-Side Update
ER-84-105	Direct	Demand-Side Update