Exhibit No.:	____________
Issue(s):	Storm URI/MPPM/FAC
Witness/Type of Exhibit:	Mantle/Rebuttal
Sponsoring Party:	Public Counsel
Case No.:	ER-2021-0312

REBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY

FILE NO. ER-2021-0312

** **

Denotes Highly Confidential and Confidential Information that has been Redacted

December 20, 2021

PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	))))))	Case No. ER-2021-0312

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 20th day of December 2021.

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.

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REBUTTAL TESTIMONY

OF

LENA M. MANTLE, P.E.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CASE NO. ER-2021-0312

Q. What is your name?

A. Lena M. Mantle.

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

A. Yes, I am.

Q. Why are you filing rebuttal testimony?

A. In his direct testimony, The Empire District Electric Company d/b/a Liberty ("Empire") witness Timothy N. Wilson says that Empire undertook significant efforts "to reduce customer rate impacts, including the unprecedented effects of Winter Storm Uri". In this rebuttal testimony, I show how the exact opposite is true. I show how the methodology Empire requested for Storm Uri cost recovery in this case would result in customers paying almost as much in earnings to the shareholders as it recovers for its Storm Uri costs. I show how the amount chosen by Empire as extraordinary increased the earnings of its shareholders. I show how the magnitude of the costs of Storm Uri were increased due to Empire's actions. Finally, I provide recommendations that would mitigate the impact of the Storm Uri costs on Empire's Missouri customers.

I also provide clarification of the Market Price Protection Mechanism ("MPPM") beyond what Empire and other parties provided in their direct and show why clarification is necessary.

Finally, I respond to Empire's proposed changes to its Fuel Adjustment Clause ("FAC") and add to Staff's requested additional FAC reporting requirements.

Storm Uri Extraordinary Cost Treatment

Q. When the Commission considers the extraordinary costs that Empire accrued to provide service during Storm Uri in determining Empire's new rates in this case, what do you recommend that it do?

A. I recommend that, when the Commission determines Empire's revenue requirement for ratemaking and for designing Empire's new rates, it do the following regarding the extraordinary storm cost:

1. Exclude from Empire's revenue requirement Empire's ordinary fuel and purchased power costs during Storm Uri, i.e., Empire's normalized level of fuel and purchased power costs for February 2021;
2. Exclude from Empire's revenue requirement five percent of Empire's extraordinary fuel and purchased power costs (Fuel and purchased power costs that could flow through Empire's FAC if they were not extraordinary);[1]
3. After excluding ordinary fuel and purchased power costs, and five percent of Empire's extraordinary fuel and purchased power costs from Empire's total extraordinary costs due to Storm Uri, amortize one-half of the balance over an appropriate period, so that Empire's customers and shareholders equally shoulder that extraordinary cost Empire incurred to provide service during Storm Uri;
4. Create an the annual amortized amount in Empire's revenue requirement as an expense, not rate base; and
5. When designing Empire's new rates, design them so that the extraordinary Storm Uri costs to be collected from customers are collected on a usage basis, and based on an amortization period that results in a kWh cost of less than \$0.0075, but does not exceed ten years.

[1] The 5% that does not flow through the FAC is not 5% of the total Missouri fuel and purchased power costs. It is 5% of the difference between what was actually incurred and what was collected in permanent rates. For February 2021, the amount is actually 4.72% of Missouri jurisdictional fuel and purchased power costs.

Q. What is Empire's proposal for how the Commission should consider its Storm Uri costs when it determines Empire's new rates?

A. Empire is seeking to recover 100% of the fuel and purchased power costs it incurred in February 2021 due to the extreme weather event also referred to as Storm Uri. The total costs that Empire included in its direct case are $182 million.[2] Empire is asking the Commission to amortize this $182 million over 13 years, a recovery of almost $14 million a year.[3] Empire is also requesting that the Commission include this $182 million in its rate base on which its shareholders receive a profit and a gross up for income taxes would be required. As of its direct filed on May 28, 2021, Empire is requesting an incremental increase in its revenue requirement of $29.9 million for Storm Uri costs in this case.

Q. Did not Empire witness Timothy N. Wilson say, in his direct testimony in this case, that it would withdraw its request for recovery of Storm Uri costs and seek to recover them through securitization if securitization became law?[4]

A. Yes. Empire filed notices of its intent to file an application for securitization of its Storm Uri costs on August 13 and 28, 2021; however, to date, it has not filed such an application.[5].

Q. What does Staff recommend that the Commission do with Storm Uri costs when it determines Empire's new rates in this case?

A. Staff recommends that the Commission not address them in this case in anticipation that Empire will seek to securitize them.[6]

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[2] The increase to rate base provided on page 21 in the direct testimony of Empire witness Emery of $181,692,727 is the amount included in rate base after accounting for the CWC impact.
[33] $182 million divided by 13.
[4] Page 7.
[5] The notices are filed in case EO-2022-0040.
[6] *Staff Cost of Service Report*, page 2.

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Q. What does MECG recommend that the Commission do with Storm Uri costs when it determines Empire's new rates in this case?

A. MECG opposes the Commission allowing Empire to profit on, *i.e.,* get a return on, its Storm Uri costs.

Q. Has Empire done, or failed to do, anything that affects the amount of the extraordinary Storm Uri costs that are at issue in this case?

A. Yes. There are at least two. First, Empire changed the objective of its resource planning from assuring it has sufficient resources to serve its native load to maximizing its revenue from the Southwest Power Pool ("SPP") integrated market. Second, Empire is defining all of the fuel and purchased power costs that it incurred, but did not flow through its FAC for the accumulation period that includes February 2021 to be extraordinary.

Q. What do you recommend that the Commission do with Storm Uri costs when it determines Empire's new rates in this case?

A. There are many actions that the Commission can take to reduce the impact of Empire's extraordinary storm costs on Empire's customers.[7] Among them, in this case when determining Empire's rates, the Commission could:

1. Exclude them from Empire's rate base, and not include any carrying costs, return on them, or tax gross-up in revenue requirement;
2. Since the Commission excludes recovery of 5% of Empire's fuel and purchased power costs recovered through its FAC, exclude 5% of the Missouri jurisdictional cost after an adjustment for costs recovered in permanent rates. That 5% is what the Commission intends, in Empire's FAC, to incent Empire to efficiently manage its fuel and purchased power costs; and

[7] OPC reserves the right to look further into the prudence of actions taken by Empire during Storm Uri.

3. Equally split the remaining Storm Uri costs between shareholders and customers.

Requested Revenue Requirement Treatment

Q. How does the $14 million a year amortization of the storm costs Empire is requesting end up being an increase of almost $30 million in its annual revenue requirement for recovery from its customers?

A. Empire is asking for $182 million of Storm Uri costs to be treated as rate base creating an earnings opportunity for its shareholders. My review of Empire witness Charlotte Emery's Schedule CTE-1 shows that an amount of $4 million for income taxes is deducted from the $14 million amortization resulting in an operating loss of $10 million. A return of $13 million on the $182 million of capitalized expense is added to the operating loss of $10 resulting in an income deficiency (or revenue deficiency) of $23 million. This revenue deficiency is multiplied by a gross revenue conversion factor of 1.313 to account for state and federal income taxes resulting in Empire's $29.9 million revenue requirement amount for its Storm Uri costs. This is how the $14 million annual amortization of storm costs ends up being a revenue requirement of $29.9 million. This calculation is shown in the table below.

Table 1
How Empire is Using Storm Costs to Earn a Return

		in million $
Rate Base		$182
Return requested	7.03%	$13
Amortization (years)	13 years	$14 /yr
Income tax		($4)
Income deficiency		$10
Income Deficiency		$23
Gross Rev Conversion Factor	1.313	
Revenue Deficiency		$30
Revenue Requirement		**$30**

Q. How much of this revenue requirement is earnings for Empire's shareholders?

A. Empire is asking that its shareholders be rewarded <u>a return of $13 million a year</u> from its ratepayers on the costs it incurred during Storm Uri, costs that Empire did not incur to repair or replace physical assets.

Q. Has Empire's estimate of its Storm Uri costs changed since it filed this rate case?

A. Yes. In its FAC rate change case, ER-2022-0095, Empire deferred an additional $23.6 million of costs it associates with Storm Uri that it realized after February 2021.[8] Of this amount, $12.3 million was attributed to the cost of natural gas that Empire nominated in February to generate additional electricity in February but, due to pipeline constraints during Storm Uri, Empire was not able to take delivery of until March 2021. The rest of the deferred cost, $11.3 million Southwest Power

[8] ER-2022-0095, Direct testimony of Charlotte T. Emery, page 8.

Pool ("SPP") market resettlements cost for February 13 through 19 that were charged Empire in April 2021[9] and June 2021[10].

In addition to the deferment of $23.6 million, Empire stated in testimony in case ER-2022-0095 that it would include in its accounting authority order request case, EU-2021-0274, the 5% of these costs that it could not recover if these costs were included in Empire's FAC.[11]

Q. Applying the approach to Storm Uri costs that Empire took in its direct case, how much do these foregoing later realized costs add to the revenue requirement Empire requested in its direct testimony?

A. Using direct testimony workpapers provided by Empire witness Charlotte Emery in this case and Empire's last FAC rate change case, case ER-2022-0095, I estimate these costs would increase Empire's Storm Uri rate base total cost to $207.2 million. The revenue requirement for Storm Uri costs would be $33.9 million if the Commission approved the treatment that Empire is requesting. The shareholder earnings would be $14.6 million a year.

Q. Is this the case where the Commission should consider the rate impacts of Storm Uri?

A. Yes. The costs were incurred in the update period for this case. The costs are known. Empire has included Storm Uri costs in its direct case that it filed May 28, 2021. There is no reason to put off treatment of these costs to the next rate case.

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[9] First SPP market resettlement.
[10] Second SPP market resettlement.
[11] ER-2022-0095, Direct testimony of Charlotte T. Emery, page 9, total of $1.2 million.

Q. Why does Empire's proposal for how the Commission should consider its Storm Uri costs when it determines Empire's new rates maximize its shareholders' profit?

A. By requesting Storm Uri costs be included in its rate base, the more the cost deferred upon which carrying costs are applied at Empires' weighted actual cost of capital, the greater Empire's profit paid by its customers to its shareholders.

Determination of "Ordinary Costs"

Q. What is the significance of the split of costs between ordinary and extraordinary?

A. Commission rule 20 CSR 4240-20.090(8)(A)2.(XI) requires the electric utility to identify the extraordinary costs that were not passed through the FAC when filing for a FAC rate change. It does not define what are "ordinary" costs or what are "extraordinary" costs. The Oxford dictionary defines "ordinary" to be what is "commonplace" or "standard."

Q. What of Empire's Storm Uri costs are extraordinary?

A. There is no pre-determined manner to determine what are "ordinary" costs and what are "extraordinary" costs. Reasonable minds can differ on what is an ordinary cost and what is an extraordinary cost. Parties in rate cases such as this one often make normalization adjustments to the actual costs a utility incurred during the review period—here the test year as updated—to reflect an anticipated future ongoing amount, *i.e.*, an ordinary amount. Often such adjustments are based on multi-year averages of those costs over a period of several years.

However, because whatever is not an ordinary cost is considered to be an extraordinary cost in this situation, whether an Empire fuel or purchased power cost is classified as ordinary or extraordinary impacts Empire's new rates. If a fuel or purchased power cost is classified to be ordinary, then it has a more immediate bill impact through Empire's FAC, but if that same cost is classified as extraordinary, then, if treated as Empire requests, it will have a longer-term bill impact and cost customers more, and a greater overall bill impact as the bills will include recovery of a higher return for shareholders and a tax gross-up.

There is no disagreement that Empire incurred extraordinary costs during Storm Uri. At issue is what costs did Empire incur during Storm Uri that were ordinary, to be recovered through its FAC, and which were extraordinary?

Q. What did Empire classify to be its ordinary costs and its extraordinary fuel and purchased power costs during Storm Uri?

A. First, Empire determined its actual, total system fuel and purchased power costs for February 2021. It subtracted from its total actual costs what of that cost it recovered through its permanent rates. It then applied the Missouri jurisdictional allocation factor to arrive at the total cost it said it attributed to its Missouri retail customers. Empire's FAC requires Empire to absorb 5% of this cost. Empire is to recover the other 95% from its customers through its FAC rates. The calculation of these costs is shown in the table below.

Table 2
Calculation of Missouri Retail Uncollected Storm Costs
In million $

Total Energy Cost	$217.9
Base Energy Cost[12]	12.1
Remaining Cost	205.8
MO Juris Allocation Factor	0.9007
MO Remaining Costs	$185.3
95%	$176.1
5%	$9.2

[12] Collected in base rates charged the customers in the month of February.

Q. What amount of its February 2021 costs did Empire choose to include as ordinary costs when it calculated its FAC rates for its accumulation period that includes February 2021?

A. In its FAC rate change case that included February 2021 fuel and purchased power costs,[13] Empire only included $7.3 million of its storm costs above what customers paid in permanent rates as "ordinary" fuel costs. Empire then classified all non-recovered costs above this $7.3 million as "extraordinary" costs.

Q. How did Empire choose $7.3 million of its February 2021 fuel and purchased power costs to be "ordinary" costs?

A. Empire determined that it wanted its FAC rates for the June through December 2021 recovery period for its September 2020 through February 2021 accumulation period to be zero. Empire calculated that including $7.3 million of its February 2021 fuel and purchased power costs resulted in FAC charges of a FAC rate of zero and a FAC charge of zero dollars on its customers' bills.

This is how Empire determined what fuel and purchased power costs it accrued for February 2021 were "ordinary" and what were "extraordinary."

Q. What of Empire's February 2021 fuel and purchased power costs do you consider to be ordinary?

A. The best answer that I can give is a range. The lower end of this range is easy. The lowest cost that could be considered ordinary are the costs included in Empire's current permanent rates. However, Empire's FAC is based on an assumption that there will be ordinary fluctuations around that amount included in its permanent rates. Therefore, it is reasonable to conclude the amount of costs that would raise Empire's FAC rates to the highest FAC rates the Commission has approved in the normal course of business is ordinary.

[13] Case ER-2021-0332.

Q. What is the highest Empire FAC rate that the Commission has approved?

A. The highest FAC rate for secondary customers approved by the Commission is $0.00758/kWh collected in June 2018 through November 2018 for unrecovered costs from September 2017 through February 2018.[14]

Q. Is this the upper limit of your range for ordinary fuel and purchased power costs?

A. Not necessarily. However, this demonstrates that the Commission has found that the costs Empire incurred to increase Empire's FAC rate to $0.00758/kWh were ordinary and should be recovered through its FAC.

Q. If you assume this highest FAC rate of $0.00758 is the rate for the recovery period for the September 2020 through February 2021 accumulation period, and also assume that Empire only had extraordinary fuel and purchase power costs during February 2021, how much of Empire's February 2021 fuel and purchased power costs would be ordinary?

A. The amount of ordinary costs would have been $23.5 million over the amount of ordinary costs Empire collected for that month through its general rates. Then Empire's extraordinary fuel and purchased power costs for February 2021 would have then been $152.6 million, $16.2 million lower than Empire's estimate. OPC raised this very point in its May 12, 2021, response to Staff's recommendation to Empire's FAC rate change tariff filing in Case No. ER-2021-0332, but Empire did not change its proposed zero FAC rates.

[14] Case No. ER-2018-0270.

Q. Using Empire's methodology for calculating Storm Uri costs in its revenue requirement and reducing its extraordinary Storm Uri costs by $23.5 million, what is the impact on Empire's revenue requirement request?

A. Table 3 below shows the difference that setting ordinary costs at $23.5 million would have made.

Table 3

Impact of Different Levels of "Ordinary"
Million $

			Difference
Amount considered Ordinary	$7.3	$23.5	$16.2
Amount considered Extraordinary	$192.4	$176.2	($16.2)
Rate base amount	$207.2	$191.0	($16.2)
Revenue Requirement	$33.9	$31.3	($2.6)
Shareholder profit	$14.6	$13.4	($1.2)

This table shows that if $23.5 million of the Storm Uri costs Empire treated as extraordinary are, instead classified as ordinary, then, using Empire's methodology, its revenue requirement request would be lower, as would its shareholders' earnings.

Q. Why didn't you pursue using the amount of $23.5 million for ordinary costs in Empire's Case No. ER-2021-0332 FAC rate change case?

A. As stated in *Public Counsel's Response to Staff's Recommendation* filed in that case, OPC did not pursue changing the amount considered ordinary because the proposed amount of $7.3 million was in the range of what costs could be considered ordinary.

Q. What FAC rate did the Commission approve for secondary customers in Empire's next FAC rate change case?

A. The FAC rate for secondary customers the Commission approved in the next FAC rate change case, and which is currently in effect, is $0.00712/kWh. This indicates that in Empire's very next FAC rate change case, Empire believed that ordinary costs can result in a FAC rate much higher than the cost it chose to include for its September 2020 through February 2021 FAC accumulation period.

5% of FAC costs

Q. Why should the Commission exclude five percent of Empire's extraordinary February 2021 fuel and purchased power costs when it is determining what amount to include in Empire's revenue requirement in this case?

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[15] 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. This Commission 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.[16]

However, since the advent of FACs that eliminated most of the risk of fuel cost fluctuations from utilities and moved them to their customers, I am not aware of any meaningful reduction to the return on equity the Commission authorizes.

[15] Section 386.266 RSMo.

[16] In the last Empire rate case, ER-2019-0374, I 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."

If the Commission allows Empire to collect in any manner this portion of the costs that cannot flow through its FAC, then the 5% becomes a meaningless incentive. At a bare minimum, Empire should be on the hook for the 5%. If the Commission allows Empire to recover this 5%, 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.

If the Commission allows Empire to recover this cost, 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. This should be changed going forward by the Commission drastically reducing the rate of return it allows for Empire in order to compensate Empire's customers for taking on this risk.

Q. Is Empire proposing not only recovery of this 5%, but also shareholder earnings on it?

A. Yes. In this case, not only is Empire asking the Commission to allow it to collect from its customers this amount that is supposed to be its incentive for Empire to manage its fuel and purchased power costs efficiently, it is asking the Commission to allow it to charge its customers to provide Empire's shareholders earnings on the 5%.

Q. By requesting a return of and on the 5% of FAC costs is Empire "pulling a lever" to reduce customer rate impacts?[17]

A. No. Including return of the 5% increases customer rate impacts. Earning a return on that 5% increases customer rate impacts even more.

[17] Direct testimony of Timothy N. Wilson, page 7.

Resource Planning for Customers Not Profits

Q. Were not the costs that Empire accrued due to Storm Uri beyond Empire's control?

A. 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.

But much of the extraordinary costs of Strom Uri were the consequence of long-term Empire decisions with respect to its generation resources. Empire's long-term decisions on the generating resources available to it impact its costs of an extreme event like Storm Uri. When times are good and market prices are low, just about any resource that provide 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 to match the level required by its customers will mitigate the costs the utility incurs in extreme events like the one Empire faced in February 2021.

Q. Would you explain?

A. Empire is tasked by Missouri statute with providing safe, reliable electricity at just and reasonable rates. This is best achieved with a diverse portfolio of different generation resources, each with its own strengths and weaknesses. No one type of resource on its own can meet this requirement. However, a diverse portfolio of resources can.

Before Algonquin acquired Empire, 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 a sole owner of a baseload coal plant that, had for decades, reliably provided inexpensive energy, and recently added equipment that resulted in a more efficient plant that met all environmental requirements and extended its engineering life. 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.

To supplement its solely-owned coal-fired generation, Empire acquired minority ownership of three other coal-fired, baseload generating plants. These baseload plants provided electricity at a low variable cost to Empire's customers on a continuous basis. Yet, because Empire is a minority owner, Empire has no control of operations or maintenance at these plants.

Prior to the Southwest Power Pool ("SPP") integrated energy market and, initially after the beginning of the market, these coal-fired generating plants were kept running as much 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 has changed how utilities' use their resources. The ability to dispatch and run reliably has often been overshadowed by the often-narrow margin of earnings on the energy market.[18]

Q. What are Empire's other generating resources?

A. Empire also built and owns two natural gas combined cycle plants. It is the sole owner of one and a majority owner of the another. These efficient, natural gas generating plants have been workhorses for Empire, both before and after the

[18] The SPP market monitor unit recognized this in its 2020 State of the Market Report when it reported "Given the relatively low average SPP market prices, the MMU does not expect SPP market prices to support new entry of generation investments." https://www.spp.org/documents/65161/2020%20annual%20state%20of%20the%20market%20report.pdf, page 172.

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. 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 combine cycle plants are dependent upon the gas pipelines to provide natural gas when the generation is needed. Empire has entered into firm transportation contracts for the supply of natural gas. However, as was experienced in Storm Uri, this firm contract does not necessarily mean natural gas will be physically be available when it is needed.

Empire also built and maintained some simple cycle combustion turbines that are relatively inexpensive to build,[19] 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. What about renewable generating resources?

A. Renewables are good supplemental energy sources. Empire's oldest renewable resources are its Ozark Beach hydro units. When headwaters are adequate, they are available on demand.[20].

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

[19] One or two of these could be built for the extraordinary cost Empire incurred in during Storm Uri.
[20] This resource has been restricted for other reasons beyond Empire's control like trout fishing in Arkansas.

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.

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 generating resources that can always be relied upon for electricity to meet customers' needs. Electricity is only supplied from them when the wind is blowing. When the wind is not blowing, there is no electricity from these resources, despite 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.

With the advent of the SPP integrated market and Algonquin's purchase of Empire, the planning priority for Empire's generation resource portfolio moved from having resources necessary to generate electricity to meet the needs of its customers 8,760 hours of the year to making money on the SPP market and relying on the availability in that market for electricity to meet the reliability requirements of its customers.

Q. What does this 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.

Empire had retired on its books the only coal plant that it controlled on March 1, 2019, 14 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.[21] Empire has no control over the operation of and maintenance at its other sources of baseload coal generation resources, 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.

Empire did have control over the operation and maintenance of its combined cycle natural gas plants, but that control is only meaningful when their natural gas sources can be depended on. 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.

**____ ** Because there is no fuel costs for electricity generated by these units, Empire typically runs these unit when it can. **____ **[22]

Empire's purchased power wind project, Meridian Way was **____ **[23]

[21] Empire is requesting the recovery of the remaining cost of this plant and return on that cost in this case even though its customers can not receive any benefits, in dollars or reliability of service, from this plant again increasing its earnings for its shareholders through increased rates charged its customers.
[22] February 2021 Electric Net Fuel & Purchased Power Report, February 2021 FAC monthly report, BFMR-2021-1076.
[23] *Id.*

Q. Empire witness Shaen Rooney states in his direct testimony, "During [Storm Uri], all three wind farms, which are equipped for cold weather operation, were able to generate energy." How much electricity did they generate?

A. I sent a data request to get this information. Empire responded to OPC data request 8055 for the hourly availability of each of the wind projects during February 2021 that **____** Empire also provided a spreadsheet with hourly availability in February 2021. It showed the Kings Point availability at **____ ** from the beginning of February through ** ____________________ ** indicating that it was not available during Storm Uri. This is in direct contrast to the testimony of Empire witness Shaen Rooney.

However, Empire's response to OPC data request 8035 showed that even though the Kings Point wind project was **____**

Q. How do you reconcile the responses to OPC data requests 8055 and 8035 regarding the availability of Kings Point and how much electricity was supplied from it during Storm Uri?

A. I cannot.

Q. How do the amounts the wind projects generated in February 2021 compare to what they would have been able to generate if they had been fully available in every hour in February 2021?

A. The table below shows the maximum amount of generation of each project if it had been able to generate every hour at its nameplate capacity and the actual amount of generation during the month of February.

Table 4
Actual vs Fully Available Generation

	Nameplate MW	Fully Avail MWh	Actual MWh	%
Neosho Ridge	300	201,600	**_____	__**
North Fork	149	100,128	**_____	__**
Kings Point	149	100,128	**____	_**

Q. Is it rational to assume that every wind turbine at each wind project would be available in every hour of February 2021 at its nameplate capacity?

A. No. A benefit of wind power is no fuel cost[24], not availability.

Q. Why did you include the "Fully Avail MWh" in this table?

A. While some of the difference between Fully Available MWh and Generated MWh in this table was due to the incomplete construction at two of the wind projects, Empire had taken ownership of the North Fork wind project. This table shows that while the turbines were in place and completed at North Fork, it only generated **___ ** of the amount that it would have if it generated every hour at maximum capacity. The amount of generation is dependent upon both when the wind is blowing and the wind speed even when the wind project is totally available.

The graphs below shows the daily generation of each of the three wind projects in February 2021 and the amount that each could have generated had it been fully available and the wind sufficient in each hour of the month for each turbine in it to generate electricity at its nameplate capacity.

[24] Most purchased power agreements, such as the two that Empire currently has, include a cost for each MWh of generation. For Empire that cost per MWh has been mostly higher than SPP market prices meaning these wind projects run at a loss to Empire.

Figure 1
Gap Between Intermittent and Fully Available
Neosho Ridge Wind Project ***

***

Figure 2
Gap Between Intermittent and Fully Available
North Fork Ridge Wind Project ***

***

Figure 3
Gap Between Intermittent and Fully Available
Kings Point Ridge Wind Project ***

[redacted]

***

The lines at the top of the graphs show the maximum generation output if every turbine was generating at its nameplate capacity in every hour of the day.[25] The bars show the actual generation of the wind project. These graphs show that, despite the wind turbines being available on February 8 through February 10, during Storm Uri, none of the wind projects provided electricity on those days. In addition, the highest daily generation in February of each wind project occurred before or after Storm Uri occurred.

Empire has stated many times that these wind projects would "replace" Asbury. Although we can never know what the availability of the 206 MW Asbury plant would have been in February 2021 if it had not been prematurely retired, it would not have been on outage for planned maintenance during this time. It would

[25] 149 MW multiplied by 24 hours.

have had at least a 60-day supply of fuel. Its availability would be impacted by cold weather preparedness, not the availability of fuel.

Q. Do these graphs support Empire witness Shaen Rooney's direct testimony that the wind "projects can bolster the reliability of the system as was demonstrated during [Storm Uri]"?[26]

A. No. In fact, the graphs show how the wind projects do not "bolster the reliability" of Empire's system. It does show that the projects can generate electricity. It also shows that they cannot be relied upon in any given hour for any set amount of electricity. The whims of the wind do not equate to reliability. While these wind projects may have been built where there is an abundance of wind, the availability and speed of the wind is not dependable.

Q. What does the reliability of resources have to do with fuel and purchased power costs in February 2021?

A. Empire, being a member of SPP means that SPP will pay Empire for each MWh of electricity it generates and charge Empire for the electricity it uses to meet its customers' loads. If a load serving entity in SPP, such as Empire, has resources to adequately provide for its customers, then the difference between the price SPP pays it for generated electricity and the cost SPP charges the load serving entity for energy to serve the load is simply the cost of transmission congestion.

However, Empire has changed its resource planning criteria from reliably meeting its customers' requirements at the lowest cost to customers, to adding and retiring resources based on market revenues. It has ceded its responsibility for providing reliable service for its customers to SPP, which puts the affordability of electricity also at the whims of the market.

When market prices are low and steady, this advantages customers. Customers are assured electricity at a price that can be mostly covered by revenues

[26] Page 7.

received for generation of electricity, even if the generation of electricity is at times different from when it is required to serve those customers. In this new paradigm, the excess revenues should reimburse customers for the fixed cost of the resource. If under this market paradigm, the revenues received for generation by a plant does not cover the fixed costs of a plant, then the resource is considered economically inefficient and, therefore, should be retired. Resource decisions are based on the energy market, not on providing reliable service to customers at a reasonable cost.

Empire relied on the market to provide energy for its customers where the price for energy is set by the market. SPP members had generation resources well above the load requirements, which resulted in an excess of energy availability, many times driving the price offered for generation negative. Fuel costs were low. All of this resulted in low market prices.

This worked for Empire's customers until Storm Uri. When extreme cold temperatures spread across the entire SPP footprint, the demand for electricity skyrocketed, as did the SPP market price for electricity. The high demand and resource constraints, complicated by the extreme cold and spikes in natural gas prices, drove the price SPP offered for generation extremely high. If Empire had the resources to meet its customers' requirements, the price paid for its generation would have reasonably offset much of the cost SPP charged Empire 'for serving' its load.

Q. Are you saying that Empire did not do everything that it could during Storm Uri to provide energy into the SPP market to generate revenues that offset Empire's cost to acquire energy from the SPP market to meet its load requirements?

A. No. While I have not closely examined Empire's actions during Storm Uri, I have no reason not to believe that, given the resources available to it, Empire worked diligently to sell electricity into the SPP market. However, the die had already been cast by the resources available to Empire. Extreme stress exposes resource portfolio weaknesses, and demonstrates 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.

As described above, Empire retired the only baseload plant that it had over which it had full control one year before Storm Uri. Empire's natural gas plants were constrained by the availability of fuel. Empire's dual fuel combustion turbines proved valuable, since they had fuel oil on site that Empire used to generate electricity. I have already discussed the availability of the wind resources.

When its customers needed Empire to cover the cost of the electricity they required by selling electricity from resources Empire had into the SPP market, Empire did not have electricity generating resources that could generate that electricity then when market prices were high.

Q. Do you have an estimate of the revenues Empire's Asbury plant might have provided to offset Empire's cost of electricity to serve its load if Asbury were available during Storm Uri?

A. If Asbury had been available at 206 MW for the time period of February 7 through February 24, using the North Fork day-ahead prices and the average Asbury fuel cost from February 2018, I estimate Asbury's market margin would have been almost $75 million. The impact that generation from this plant could have had on Empire's costs and its requested revenue requirement shown in the table below.

Table 5
Impact of Asbury Retirement
Million $

	Actual	With Asbury	Diff
Total Cost	$217.9	$143.3	($74.6)
Total – Cost in Rate Case	$205.8	$131.2	($74.6)
Mo Juris Cost	$185.3	$118.1	($67.2)
95%	$176.1	$112.2	($63.8)
5%	$9.3	$5.9	($3.4)
Revenue Requirement	$29.9	$22.9	($7.0)
Return to Shareholders	$12.9	$9.8	($3.1)

Q. Do you know of any utility that had a sufficient generating resource portfolio that it obtained sufficient revenues from selling energy from that portfolio into the market to offset the costs that utility incurred in that market for energy to meet their customers' loads during Storm Uri?

A. Yes. In its FAC rate change filing[27], Evergy Missouri Metro provided information that showed its market revenues exceeded its market cost by $58.2 million in its FAC accumulation period that contains February 2021.

Q. What about Evergy Missouri West?

A. Like Empire, Evergy West exposes its customers to the whims of the market by relying on the market to supply energy for its customers; however, it does so to an even greater extent than Empire.[28] In its FAC rate change case for the accumulation period that includes February 2021[29], Evergy West incurred a cost of $304.7 million above base rates.

[27] Direct Testimony of Lisa A. Starkebaum, page 6.
[28] Evergy West has a contract for capacity that does not include any energy for that capacity resulting in a reliance on the market for energy.
[29] ER-2022-0005, Direct Testimony of Lisa A. Starkebaum, page 5.

Q. What about Ameren Missouri?

A. Its fuel and purchased power costs were higher than usual, but not to the extent that it thought it necessary to remove the costs from the FAC as extraordinary. I believe that had Ameren Missouri's Callaway Energy Center been generating electricity during Storm Uri, Ameren Missouri, like Evergy Metro, would have generated more revenues than costs during Storm Uri.

Q. Why did Evergy Missouri Metro's fuel and purchased power revenues exceed its fuel and purchased power costs in February 2021?

A. Evergy Metro has generation that it can rely on. Evergy Metro had revenues greater than costs because Evergy Metro has dispatchable generation resources in excess of what its customers need.

Q. Are you suggesting that Empire should, like Evergy Missouri Metro, have excess generation?

A. No, and on a nameplate basis it already does. What I am saying is that Empire should have resources it can rely on to meet its customers' needs every hour of the year. I am saying that reliability should be at least as important as generating revenues in the SPP market when making resource planning decisions. I am saying that because Empire put more of an emphasis on resources to beat the market than on reliably providing electricity, Empire incurred tremendous costs in February 2021—not because market prices were high, but because Empire did not have generation resources that it could control and depend on to meet its customers' needs when market prices were high.

Q. But, did Empire not meet the resource adequacy requirements of SPP in 2020 and 2021?

A. Yes, it did. However, SPP's resource adequacy requirements for Empire are based on Empire's ability to meet Empire's peak load <u>for one hour</u>. Empire exceeded its forecasted peak load during Storm Uri for more than one hour. The extraordinary cost Empire incurred shows the inadequacy of its resources to meet the load requirements of its customers at a reasonable cost over an extended period of time, despite meeting the resource adequacy requirements of the SPP.

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

A. No. According to 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. How much revenue did the wind projects generate in the SPP market in February 2021?

A. *** ________________________________ *** for Neosho Ridge, Kings Point, and North Fork wind projects, respectively.[30]

Q. How have these revenues impacted Empire's revenue requirement that underlies its rate increase request?

A. The Wind Holding Company had not yet taken ownership of the Neosho Ridge or Kings Point wind projects in February 2021. Therefore, all revenues from electricity sold into the market at that time was retained by the developers of the projects. The Wind Holding Company had taken ownership of the North Fork wind project. However, because this wind project was not yet included in rate base, none of the revenues it generated will be used to offset the Storm Uri costs. Empire is proposing that these revenues be shared with its tax equity partners and then only

[30] Response to OPC DR 8035.1.

85% of the wind project revenues allocated to Empire, not be used to offset Storm Uri cost but instead be amortized and returned to customers over a two-year time period.[31]

Q. What is Empire proposing for the SPP energy market revenues in February 2021 from the two projects of which Empire's Wind Holding Company had not taken ownership in February 2021?

A. That is unclear. Empire witness Todd Mooney had said in his direct testimony[32] in the CCN case, EA-2019-0010, that Empire would receive a reduction in the purchase price of the wind projects based on the quantity of power generated. I issued a data request to get a better understanding of what Mr. Mooney meant by this statement. Empire provided the following response to my OPC data request 8082:

> Prior to Liberty acquiring a wind project, revenues generated are offset against the total capital investment of the project.

This seems to say that the capital cost paid by Empire would be reduced by the revenues received for generation prior to ownership. However, in response to my OPC DR 8081 regarding the revenues generated by each project prior to Empire closing on the project, Empire stated:

> <u>Revenues earned by the wind projects prior to the closing of the Purchase and Sale Agreements ("PSAs") were retained by the Seller</u>. Empire received a price discount to the price paid under the PSAs based on the amount of energy produced by the wind projects prior to closing the PSAs (the "Tax Benefit Adjustments"). This price reduction is reflected as a reduction to Empire's capital investment in the wind facilities. (Emphasis added).

This response reveals that the revenues generated would be retained by the seller but the purchase price would be reduced based on a tax benefit adjustment tied to

[31] Empire is increasing the rate impact on its customers by not returning 100% of the revenues. It is increasing earnings to its shareholders by not using this revenue to off-set the capital cost of the projects.
[32] Page 12.

the amount of energy produced not the revenues that the projects would receive while being built.

Q. Did you ask what the tax benefit adjustment is?

A. Yes. Empire stated in its response to my OPC DR 8081.2:

> Pursuant to the Purchase and Sale Agreements section 2.3(c), the cost-adjusted price is reduced by an amount equal to 75% of the product of $24.00 multiplied by the aggregate quantity of electric energy delivered by any Wind Turbine at the Wind Turbine to the First Closing Date; provided, however, that if the CP Satisfaction Date does not occur on or prior to March 1, 2021, the foregoing percentage shall be increased by 90% for all periods following such date.

Q. What is your understanding of Empire's response?

A. The reduction in cost due to generation before Empire took ownership was based on a percentage of the <u>production tax credits</u> that were created by the generation of electricity, not on the SPP market revenues.

Q. Has Empire estimated this discount to the capital cost?

A. Yes. Empire estimated on November 19, 2021, that this discount would be *** ______________________________ *** for Neosho Ridge, Kings Point, and North Fork wind projects, respectively.[33] This is considerably less than the SPP revenues generated by these wind projects in February 2021 alone.

Q. How does Empire's decision that the wind projects keep the revenues from SPP for electricity generated before the projects go into Empire's rate base impact its customers' rates?

A. It increases customer rates while increasing the earnings of the shareholders.

[33] Response to OPC DR 8081.2.

Recommended Treatment of Storm Uri Costs

Q. Empire witness Timothy N. Wilson states in his direct testimony "Rather than burden our customers with a significant fuel adjustment charge which would have seen rate increases of over 62% of the total bill, Empire sought to remove charges associate with this unusual event and now seeks to amortize them over a substantially longer period than the six months contemplated by the current Fuel Adjustment Clause ("FAC") structure".[34] How do you respond to this statement?

A. While I appreciate Empire not requesting the entire amount flow through its FAC, its cost recovery request in this case is incredulous, overreaching and shows little to no regard for its customers, many of whom had to choose to use electricity to stay warm or to freeze during Storm Uri.

Empire takes no responsibility for its part in the extraordinary costs that it incurred. It claimed the new wind projects provided benefits to its customers during Storm Uri, when in fact none of the revenues paid the wind projects were used to offset its Storm Uri costs. To add insult to injury, through this storm, Empire charged its customers for a plant that it retired 14 years early that could have generated much needed electricity and revenues during Storm Uri. Now Empire is asking that this extraordinary amount, along with substantial earnings for the shareholders be recovered from its customers for the next 13 years.

Further increasing the burden on its customers, Empire is requesting the small amount that it had at risk (less than 5% of the total cost) to not only be recovered from customers, but that the Commission allow it to earn a return on the Storm Uri costs for its shareholders while also asking the Commission to continue to allow it a higher return on rate base overall because of the risks it faces.

[34] The FAC rate change that brought the FAC rate to zero went into effect two days after Empire filed this rate increase case. The optics of a large increase in the FAC charge going into effect at the same time that Empire filed for a large general rate increase would not have been good for the Company.

Q. What do you recommend the Commission do when its considers the relevant factor of the extraordinary costs that Empire accrued to provide reliable service during Storm Uri when determining Empire's new rates in this case?

A. First, Empire should not be allowed to recover the 5% incentive unless the Commission greatly reduces the return on equity it allows going forward.

Second, Empire should absorb half of the costs it attributes to Storm Uri. The other half could be recovered from customers through securitization. An equal sharing of Storm Uri costs recognizes that both consumers and shareholders benefit from the utility-customer relationship, and it is unreasonable to expose only customers to risks of extraordinary events and costs. Empire has provided no justification for forcing its captive customers to pay for costs that only Empire had the ability to mitigate through its resource planning. An equitable sharing of these extraordinary costs recognizes that Empire's customers pay a risk premium to Empire for good reason. Guaranteeing Empire full cost recovery for extraordinary events would negate that reason.

Summary of Storm Uri Cost Treatment

Q. Would you summarize your testimony on the treatment of the costs incurred due to Storm Uri?

A. Storm Uri costs were extraordinary in a large part because of resource planning decisions made by Empire. The new wind projects did not reduce the Storm Uri costs Empire is requesting be recovered from customers. The retired coal plant that the customers were paying for at the time of Storm Uri would have drastically reduced the impact of the Storm.

Empire is increasing the magnitude of the cost to its customers by requesting including a recovery of the 5% incentive built into the FAC into the Storm Uri costs and then asking the Commission to allow its shareholders to earn a return on the entire cost.

Therefore, I recommend the Commission order:

1. Exclude from Empire's revenue requirement Empire's ordinary fuel and purchased power costs during Storm Uri, i.e., Empire's normalized level of fuel and purchased power costs for February 2021;
2. Exclude from Empire's revenue requirement five percent of Empire's extraordinary fuel and purchased power costs (fuel and purchased power costs that could flow through Empire's FAC if they were not extraordinary);[35]
3. After excluding ordinary fuel and purchased power costs, and five percent of Empire's extraordinary fuel and purchased power costs from Empire's total extraordinary costs due to Storm Uri, amortize one-half of the balance over an appropriate period, so that Empire's customers and shareholders equally shoulder that extraordinary cost Empire incurred to provide service during Storm Uri;
4. Create an the annual amortized amount in Empire's revenue requirement as an expense, not rate base; and
5. When designing Empire's new rates, design them so that the extraordinary Storm Uri costs to be collected from customers are collected on a usage basis, and based on an amortization period that results in a kWh cost of less than $0.0075, but does not exceed ten years.

These actions would truly mitigate the cost impact of Storm Uri on Empire's customers.

[35] The 5% that does not flow through the FAC is not 5% of the total Missouri fuel and purchased power costs. It is 5% of the difference between what was actually incurred and what was collected in permanent rates. For February 2021, the amount is actually 4.72% of Missouri jurisdictional fuel and purchased power costs.

Market Price Protection Mechanism

Q. Do any Empire witnesses testify regarding the Market Price Protection Mechanism ("MPPM") in their direct testimony?

A. Yes. In his direct testimony Empire witness Tim Wilson identifies Empire witness Aaron J. Doll as Empire's witness for the MPPM. However, in his testimony at page 18 Mr. Doll only states that, with regard to Empire's FAC, "the Company must create a mechanism to support any distributions from the MPPM as ordered by the Commission in File No. EA-2019-0010 and as described by Empire witness Tisha Sanderson in her Direct Testimony in this proceeding."

Q. What does Ms. Sanderson say about the MPPM?

A. She gives a brief history and general overview of the MPPM on pages 12-14 of her direct testimony.

Q. Does the Staff address the MPPM in direct?

A. No.

Q. Does any other party's witness address the MPPM in direct?

A. Only me for Public Counsel.

Q. Why are you testifying about the MPPM now?

A. First, when the Commission approved the MPPM June 19, 2019, in Case No. EA-2019-0010 as part of a *Non-Unanimous Stipulation and Agreement* the MPPM was designed based on estimates of the total capital investment in the wind projects, as well as other inputs. The actual total capital investment in the wind projects is well above that estimate, and the estimates for other inputs have changed too. With these changed estimates, the MPPM may not provide the protections the Commission thought it was approving. Second, terms of the MPPM are unclear and, based on their discovery responses, signatories to the *Non-Unanimous Stipulation and Agreement* appear not to agree to their meaning. This lack of clarity could result in moving more risk from shareholders to customers than what the Commission intended.

Q. Does anyone discuss in prefiled direct testimony changes to the estimate of the total capital investment in the wind projects or other inputs to the MPPM and their impacts on Empire's shareholders and/or customers?

A. No, but Empire witness Todd Mooney testifies that Empire's actual investment in the wind projects at the time he wrote his direct testimony was *** __________ *** more than Empire's estimate of its investment in those projects in 2019.[36]

Q. As to MPPM inputs, what have changed?

A. I requested in OPC data request 8075 that Empire update its Exhibits to the MPPM Appendix in the Commission-approved *Non-Unanimous Stipulation and Agreement*. Those spreadsheets show an increase in the capital investment in the wind projects of *** ___ ***. They also show an increase in the estimates of fixed operations and maintenance expense increased, and in the estimates of income tax and property tax. The only "expense" Empire did not increase is paygo, which really is not an expense. All these increased estimated investment and expenses result in a higher wind revenue requirement ("WRR") in the MPPM spreadsheets.

Empire also estimated higher wind project revenues, but did not disclose what drove that increase—which could be due to higher estimated market prices, higher estimated MWhs of electricity generated, and/or other factors. Empire also increased the Elk River and Meridian Way PPA replacement value. Additionally, in its updated spreadsheets, Empire included revenues from the sale of renewable energy credits ("RECs") and the value of production tax credits—revenues that were not included in the exhibits attached to the Commission-approved *Non-Unanimous Stipulation and Agreement*.

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[36] Page 5.

Q. What does an increased WRR mean for Empire's shareholders and customers?

A. A higher WRR means higher earnings for shareholders. It also means that it is more likely that, after collecting estimated earnings of **__________ ** from ratepayers over ten years, Empire will be returning $26.25 million to customers.

Higher investment and expenses mean higher rates for customers beginning with the effective date of rates in this case and continuing for the 30-year depreciation lives of these wind projects. They also reduce the likelihood that revenues from the wind projects will be greater than the overall costs of the projects to customers.

Q. With Empire's updates to the MPPM cost and revenue inputs, what does Empire project the impact on its customers to be at the end of ten years?

A. In the MPPM, an Annual Wind Value is calculated each year as the revenues net of the costs in the MPPM. A negative number indicates Empire is projecting a loss. The updated expected case MPPM provided in response to my data request 8075, shows a cumulative Annual Wind Value for Empire's expected case, across ten years, to be a loss of **__________ **.

This means that for the first ten years after the wind projects are included in rates, the increase in the WRR was not completely offset by the estimated increase in SPP market revenues, the addition of REC revenues and PTC values and Empire's expected increase in the PPA replacement value. Empire expects the costs to the customers to be greater than the revenues by **__________ **.

Q. How does that compare to the expected cumulative Annual Wind Value in the MPPM provided in the *Non-unanimous Stipulation and Agreement*?

A. The expected case in the Appendix B attached to the *Non-unanimous Stipulation and Agreement* shows a cumulative Annual Wind Value at the end of year ten as a positive **__________ **

Empire's expected costs and revenues over the first ten years of the wind projects has swung by $170 million, going from an expected profit for customers to an expected loss.

Q. Since the signatories to the MPPM, other than Empire, did not explain in their prefiled direct testimony how to implement the MPPM, what did you do?

A. I issued the same set of nine data requests to the parties in this rate case who signed the *Non-Unanimous Stipulation and Agreement*. These data requests along with the responses of Empire, Staff, MECG and Renew Missouri are attached to this testimony as Schedule LMM-R-1.

Q. What did you learn from their responses?

A. Not much. It seems the only thing that all the parties come close to agreeing to is the purpose of the MPPM. According to Empire, Staff, and MECG, the MPPM is a mechanism to share the risk between customers and shareholders associated with the possibility of market prices and/or wind production less than Empire projected for its economic justifications for these wind projects.[37] Renew Missouri's response as to the purpose of the MPPM was to refer to the following statement in the Commission's *Report and Order* in that case, "In general terms, the Market Price Protection Mechanism provides for the sharing of risk between customers and shareholders associated with the possibility that the Wind Projects do not generate enough revenue."[38]

Q. Is the purpose of the MPPM to share between customers and shareholders the risk that the wind projects generate less revenues than Empire projected?

A. Yes, but it limits shareholders' exposure to how much of that risk they share and when they actually would realize their risk exposure. Customer's exposure is

[37] Page 9.
[38] Page 27.

unlimited and their risk exposure begins with the effective date of rates from this case.

Q. What do you mean?

A. In years one through ten, customers bear all the risk. Only at the end of the ten years are shareholders exposed to realizing their risk that the costs over those ten years exceed the revenues over those same ten years. At that time shareholders are exposed to reimbursing customers one-half of up to $52.5 million ($26.25) over an amortization period the Commission determines then. If losses over the ten years exceed $52.5 million, the MPPM states that the Commission is to determine how to treat the losses.

Q. Does the MPPM allocate risk between customers and shareholders?

A. Yes, but unfairly.

Q. Why do you characterize the risk allocation as being unfair?

A. Empire's capital investment in the wind projects creates the largest cost impact—increased bills—to customers. That impact begins the minute Empire's capital investment in the wind projects is embedded into their rates. In addition to Empire's capital investment, shareholder earnings for that investment is also embedded into customers' rates. Those earnings are independent of when the wind blows or what the market prices are. There is no risk that shareholders will not receive a return on or of Empire's capital investment in the wind projects.

Empire's customers assume all of the market risk in years one through ten through rates they will pay for Empire's capital investment in the wind projects, plus a return on that capital investment to reward Empire's shareholders for the risk they are taking. In return, Empire's customers receive an unknown revenue stream in years one through five that depends not only upon when the wind is blowing, but also on the market price at the time the wind is blowing. In years six through ten, customers will only receive 60% of the revenues; the other 40% will go to the wind projects' tax equity partners.

Further, as a part of the tax equity agreement, customers will pay the Wind Holding Company a "hedge" for the possibility that the market price is not high enough. While during the first five years this hedge comes back to the customers, in years six through ten, 40% of the hedge above market price will go to the tax equity partners.

Also, customers will ultimately pay for amounts to SPP to take power from the wind projects when the market price is negative so that the tax equity partners can realize production tax credits. For example, if the production tax credit is $24/MWh, the market price for energy is -$10/MWh during a particular hour, and the wind projects can generate 100 MW during that hour. In order for the tax equity partners to realize the $2,400 of production tax credits[39] for that hour, customers must pay SPP $1,000 to take the generation.[40] During that hour, customers will pay so tax equity partners will earn.

So, there are provisions in the tax equity agreement to assure the tax equity partners are made whole. Empire's shareholders get their investment in the wind projects back plus earnings on that investment while incurring a limited risk ten years out. However, customers pay, not only the shareholders capital investment in the wind projects, but also the shareholders' earnings on that investment, both of which are grossed-up for income taxes. In exchange, customers get the revenue streams from the sale of the wind projects' electricity in the SPP market.

Because those wind project revenue streams are based on market prices and generation, there is no certainty as to the amount of revenues that the wind projects will generate. However, those revenue streams are managed, not to maximize revenues for customers, but to assure that the tax equity partners are made whole,

[39] 100 MW * 1 hour * $24/MWh = $2,400.
[40] 100 MW * 1 hour * -$10/MWh = -$1,000.

i.e., to assure the tax equity partners that they get both their investment back, plus their intended profit on that investment. For assuming all this risk, customers get a promise that they will get up to $26.25 million in ten years, if the revenues from the wind projects are less than the costs of those wind projects over those ten years.

This is what is most important about the MPPM - tracking the wind projects' revenues and costs. To do that requires defining exactly the specific costs and revenues that are included in the MPPM.

Q. Would you give an example of how it appears signatories to the *Non-Unanimous Stipulation and Agreement* do not agree on how to implement the MPPM?

A. Yes. In its discovery response Empire states that the rate base amount against which the revenue stream is compared should be updated at each general rate case. Renew Missouri, did not really say what its position was in its discovery response, but it stated that, if the amount of rate base was not addressed in the Commission's Report and Order in Case No. EA-2019-0010, then the rate base cost to the customers is generally determined in rate cases. This response could be characterized as agreeing with Empire. Staff's response is that the rate base amount included in the MPPM should be changed annually corresponding not to what customers were actually paying, but to a book value that gets updated each year. MECG, again a signatory to the *Non-unanimous Stipulation and Agreement*, provided that it did not have a position on this critical cost component of the MPPM.

Q. Why does it matter whether the rate base cost included in the MPPM changes annually or at each rate case?

A. The purpose that all of the signatories agreed to was that this mechanism was to provide for sharing of the risk that market prices would not provide enough revenue to cover the costs—costs, including earnings for shareholders—that are charged to customers. Under perfect regulation, the rate base would decrease each year, and so would the amount of shareholders' earnings that customers pay. This is the amount, which decreases every year, to which Staff believes the revenues from the wind projects should be compared.

However, if Empire does not request another rate increase before it must in order to continue its FAC, then customers will be paying for the rate base as it is set in this case for four years. The rate base and earnings will not decline every year. Staff's proposal does not capture all of the costs actually paid by customers which shifts risk from shareholders to captive customers.

Q. Can you quantify what customers would pay if the Commission adopted Staff's position, but which is not be reflected in the MPPM?

A. Yes, with some assumptions. The updated MPPM calculations Empire provided in response to OPC DR 8075 shows the wind projects carrying charge decreasing by **__________ ** between year one and four. If Empire does not file another rate case for four years, customers would have paid **__________ ** that was not reflected in the MPPM. Of that **____________________ ** would go to shareholders.

Therefore, if the Commission adopted the Staff's position and Empire did not come in for a rate for four years after this case, customers would pay **__________ ** that would not be included in the MPPM in that first four years.

Q. How often should the rate base amount be changed in the MPPM?

A. I agree with Empire and Renew Missouri that the rate base component of cost included in the MPPM should only change when new rates go into effect. This would accurately track the costs paid by the customers.

Q. Are there other areas of the MPPM that need to be clarified?

A. Yes. MECG and Renew Missouri, to the extent not addressed in the Commission's *Report and Order* in EA-2019-0010, do not take positions on what revenues should be included in the MPPM.[41] Staff's position is that only the SPP market revenues should be included in the MPPM.[42] Empire's position is that the revenues ought to reflect any revenue source that can be passed back to customers as an immediate offset to their base rates.[43]

Q. What did the Commission say in its Case No. EA-2019-0010 *Report and Order* about the revenues that are to be included in the MPPM?

A. In the Decision section of its *Report and Order*, the Commission states:

> The Market Price Protection Mechanism is designed to mitigate risks to the customers of the revenues from the Wind Projects not being as expected and adds a layer of protection for the low probability events related to supply side generation."[44]

Appendix B to the *Non-unanimous Stipulation and Agreement* attached to that Report and Order provides a framework for the MPPM. It only includes SPP market revenues paid the Wind Projects in its definition of the revenues to offset the wind revenue requirement.[45] However, Appendix B does mention that paygo should also be included in the MPPM calculations.[46] There is no mention of RECs or the value of the production tax credits being included in the MPPM calculations.

[41] Responses to OPC DRs 8095 and 8104 respectively.
[42] Response to DR 290.
[43] Response to OPC DR 8086.
[44] Page 49.
[45] Appendices A and B, page 17.
[46] *Id*.

Q. Do you agree with Staff's or Empire's positions with respect to the revenues to be included in the MPPM calculations?

A. No. As I stated in my direct testimony, all sources of revenue should be included so I do not agree with Staff's position of only SPP market revenues being included.

Empire in its data request response lists revenue streams that should be included as SPP market revenues— revenues from the sale of RECs, paygo,[47] and a revenue stream consistent with the value of any production tax credits Empire may receive. This is consistent with the revenue streams that I proposed being included in the MPPM in my direct testimony.[48] However, Empire limits the revenues that are included in the MPPM to the revenues that can be passed back to the customers as an immediate offset to base rates.

Q. Did Empire clarify what that means?

A. No, not in its discovery response.

Q. Are you aware of anything that might shed light on what Empire means?

A. Yes. I am not aware of any rate mechanism other than a FAC that could be used to flow revenues back to customers on even a semi-immediate basis,[49] and Empire is proposing changes to its FAC consistent with including in its MPPM calculations as revenues that flow back to its customers through its FAC.

As I explain in detail in my direct testimony and in the last section of this testimony regarding Empire's FAC, paygo and the values of production tax credits cannot flow through a FAC. If the Commission adopts my recommendation regarding what can flow through Empire's FAC and also adopts Empire's position that only revenues that are passed back to customers as an immediate offset to base

[47] A payment made to the wind project holding company from the tax equity partner when the number of production tax credits achieved by the wind project is greater than a pre-determine amount.
[48] Page 15.
[49] Current FAC and Empire's modified FAC only changes two times a year.

rates can be included in the MPPM calculations, then only the SPP revenues and revenues from the sale of RECs could be included in those MPPM calculations.

Q. Do the spreadsheets included as exhibits to the *Non-Unanimous Stipulation and Agreement* when the Commission approved that agreement clarify whether revenues from the sale of RECs and production tax credit values are included in the MPPM?

A. Yes. They were not explicitly included in the MPPM calculations.

Q. Did Empire include them in its updated MPPM calculations that it provided in response to OPC data request 8075?

A. Yes.

Q. If Empire's estimated REC revenues and estimated production tax credits are excluded from its updated MPPM calculations, what is the resulting estimated cumulative Annual Wind Value?

A. Without these revenues, the cumulative Annual Wind Value of the MPPM provided in response to data request 8075 is an estimated negative **__________ **.

Q. How does including more revenues in the MPPM calculations affect the sharing of risk between customers and shareholders?

A. Including all revenues streams, whether they are immediately returned to customers or returned through amortizations in the next rate case, would move risk away from shareholders. It would increase the revenues included and, thus, reduce the possible amount that shareholders would be required to return to customers after year ten.

If the Commission agrees that since it is a <u>market price</u> protection mechanism the only revenues that flow through the MPPM are SPP market revenues, that decreases the probability that the revenues in the MPPM exceed the cost, thus increasing the risk to shareholders.

Q. Do you know of any way to effectuate flowing the MPPM impacts of 100% of SPP market revenues to customers between general rate cases?

A. I am not aware of a mechanism that would allow these revenues to be an offset to base rates between rate cases.

Q. Do you know how other the parties see the relationship between the MPPM and Empire's FAC?

A. I asked data requests in an attempt to get an understanding of how each of the signatory parties thought the MPPM would interact with Empire's FAC. MECG and Renew Missouri did not have a position on how the two mechanisms would interact beyond what is in the Commission's Case No. EA-2019-0010 *Report and Order*.

Q. Does the Commission address any interplay between the MPPM and Empire's FAC in that *Report and Order*?

A. No. The Commission does mention that SPP revenue from Empire's generation does flow through Empire's FAC in its *Report and Order,*[50] but it does not mention or discuss interaction of the MPPM and Empire's FAC.

Q. How did Staff respond to your data request about interplay between the MPPM and Empire's FAC?

A. Staff recognized that the MPPM and the FAC had shared components, but believes that the MPPM does not impact the FAC.

Q. Do you agree with Staff?

A. I agree with Staff that the MPPM and Empire's FAC are likely to have shared components, and also believe that the MPPM should not impact Empire's FAC. However, Empire's FAC could affect the MPPM.

[50] Page 37.

Q. Would you explain how Empire's FAC could affect the MPPM calculations?

A. Empire envisions that the revenues that are included in the MPPM should be immediately flowed through its FAC. If the Commission adopts that position, then only the SPP market revenues and the revenues for the sale of RECs could be included in the MPPM. As I described in my direct testimony, paygo and the value of tax equity payments are not fuel or purchased power costs and, therefore, would not flow through the FAC.

So, if the Commission chooses Empire's position regarding the revenues that are included in the MPPM calculations, then either the revenues included the MPPM changes or the FAC changes.

Q. Is there other interplay between the MPPM and Empire's FAC?

A. Yes. The FAC includes an incentive mechanism that requires Empire to absorb 5% of the cost above what is included in base rates or keep 5% of the cost savings. This would require Empire to track the differences in the total MPPM revenues and cost, and what flows through its FAC. Regulatory assets and liabilities for each of the costs and revenues would have to be applied in the next rate case to assure both customers and shareholders that all revenues are received by the customers and all costs are paid by the customers.

An alternative is to modify Empire's FAC so that 100% of the MPPM costs and revenues flow through the FAC, while the 5% incentive still applies to the rest of the FAC costs and revenues.

Q. If the Commission were to adopt Staff's position that only SPP market revenues be included in the MPPM calculations, would this mean that customers could not receive the revenues from wind projects' REC sales through Empire's FAC?

A. No. Revenues from the sale of RECs should flow through Empire's FAC regardless of whether the REC revenues are included in the MPPM calculations.

Q. What was Empire's response to your data request about the interplay of the MPPM and Empire's FAC?

A. Empire's response was that the MPPM "does not specifically contemplate interaction with the FAC." This response leads to confusion when compared to Empire's response to the revenues that are included in the FAC, leading me to wonder how exactly Empire proposes to pass revenues back to customers as an immediate offset to their base rates. This is indicative of the confusion regarding the implementation of the MPPM.

Q. Did the parties who signed the *Non-Unanimous Stipulation and Agreement* agree on what costs should be included in the MPPM calculations?

A. No. Again, MECG and Renew Missouri did not have a position on the costs that should be included in the mechanism they agreed to other than what might be in the Commission's *Report and Order*.[51]

In response to the question regarding "Wind Revenue Requirement" as used in the MPPM, "What are each and every one of the types of costs that are to be included in the 'SPP Market Revenue'?," Staff responded, "No costs were to be included as a SPP Market Revenue."[52] While it is correct that no costs are included in the SPP Market Revenue, Staff did not offer what costs are included in the Wind Revenue Requirement.

Q. What was Empire's response?

A. It responded[53] that the costs would include operational expenses directly related to wind project operations and, in a future period, reductions to net income from the wind projects as a result of the tax equity distributions.

[51] OPC DRs 8096 and 8105 respectively.
[52] DR 291.
[53] OPC DR 8087.

Q. Did Empire state that the wind project capital costs are part of the wind revenue requirement?

A. No, it did not.

Q. Did Empire state that earnings for shareholders and cost of debt are part of the wind revenue requirements?

A. No.

Q. Did Empire say anything about income and property taxes as costs that are inputs into the MPPM calculations?

A. Empire did not mention them as costs that were included in the MPPM.

Q. Is the "reductions to net income" Empire mentioned in its answer a cost?

A. No. A reduction in income is not a cost. It is less income.

Q. What did the Commission say in its *Report and Order* in Case No. EA-2019-0010 about costs to be included in the MPPM calculations?

A. The Commission found:

> The Market Price Protection Mechanism will factor in actual interconnection costs, tax equity cash distributions and PAYGO contributions, ongoing operation and maintenance costs, and curtailment.[54]

Q. Is Empire's list the same as the Commission's list?

A. No, there are some differences.

Q. What costs should be included?

A. As I testified in my direct testimony, the MPPM should include all of the costs customers will be paying. [55] This includes operation and maintenance costs, labor, tax equity payments, property taxes, return on and of the capital costs, and income taxes specified in Appendix B to the *Non-unanimous Stipulation and Agreement*

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[54] Page 28.
[55] Pages 12-13.

the Commission approved. The cost of renewable energy credits ("RECs") Empire will be paying for should also be included.

Paygo is not a cost. It is a revenue stream to Empire. I also separate the costs of the RECs Empire is required to buy, from the revenues that Empire might receive for those RECs at a later time.

Q. Is your list comprehensive?

A. To the best of my knowledge, it includes all of the costs of the wind projects.

Q. What about the hedge payments that are part of the tax equity partner agreements?

A. They are not costs. These payments are not a price hedge that can benefit Empire or its customers. As a condition of its contract with its tax equity partners, Empire will be making a payment for every MWh of generation to assure a certain revenue for each MWh. Therefore, these payments are a price hedge for the tax equity partners.

In years one through five, the hedge payments Empire will make should flow back to Empire. Beginning in year six, for any hour that the price paid by the SPP market for generation is less than the hedge, 40% of the hedge difference will go to the tax equity partner.

Q. Should any of the hedge payments be included in the MPPM calculations?

A. No. The hedge payments should not be included in the revenue requirement at all. Empire has assured the Commission that this is a flow through in years one through five, and that the SPP market prices will be above the hedge price in years six through ten. In years six through ten, if SPP market prices are not higher than the hedge price, customers should not be burdened with that additional cost.

Q. Should any of the hedge payments flow through Empire's FAC?

A. No. It is not a hedge that could ever benefit customers. A hedge payment is a condition of Empire's contract with its tax equity partners to assure a certain revenue for each MWh. Therefore, these payments are a price hedge for the tax equity partners and provide no benefit to customers.

Q. Did you ask the signatory parties to provide more information about the Elk River and Meridian Way PPA replacement value for the MPPM?

A. Yes. I asked each party for its understanding of the purpose of the PPA replacement value and how that value was should be calculated.

Q. How did they respond?

A. Like many of its responses to discovery requests about the MPPM, MECG stated that it did not have a position on the purpose of the PPA replacement value, other than to refer to the Commission's Case No. EA-2019-0010 *Report and Order*.[56] Renew Missouri simply stated that the purpose of the PPA replacement value was the value defined in Appendix B attached to that *Report and Order*.[57]

Q. How is PPA replacement value defined in that Report and Order?

A. I do not find a definition for the PPA replacement value in the text of that *Report and Order*. The Commission does state in that Report and Order that one of the benefits of the wind projects is that they would replace the expiring Elk River and Meridian Way wind generation contracts.[58] In Appendix B attached to the Commission's *Report and Order*, the PPA replacement value is defined as the value associated with replacing the existing wind PPAs during the period of the

[56] Data request 8099.
[57] Data request 8108.
[58] Page 22.

guarantee.[59] Exhibit B also states the PPA replacement value "shows the amount of benefit associated by year with the existing wind power purchase agreements."[60]

Q. What were Staff's and Empire's responses for the purpose of the PPA replacement value in the MPPM?

A. Staff responded that the purpose of the PPA replacement value was that it was a part of a negotiated settlement, and that the value is associated with replacing the existing wind PPAs during the period of the guarantee.[61]

Empire answered that the purpose is to reflect the value that the new wind farms will have for meeting the Renewable Energy Standards as a replacement for the current Elk River and Meridian Way wind PPAs.[62]

Q. How did the other signatories to the *Non-unanimous Stipulation and Agreement* who are parties to this case respond to your discovery for how to calculate the PPA replacement value?

A. MECG stated that, if the calculation of the PPA replacement value was not included in the Commission's *Report and Order*, MECG did not taken a position on how to calculate it.[63] Renew Missouri replied that if it was not addressed in the *Report and Order*, then it did not have a position on how to calculate it.[64]

Q. What did the Commission say about how to calculate the PPA replacement value in its Report and Order in Case No. EA-2019-0010?

A. Nothing.

[59] Page 16.
[60] Page 17.
[61] Data request 294.
[62] Data request 8090.
[63] Data request 8100.
[64] Data request 8109.

Q. How did Staff respond to your discovery for how to calculate the PPA replacement value?

A. Staff's responded that the PPA replacement value was the value associated with replacing the existing wind PPAs during the period of the guarantee.[65] It gave no methodology for calculating the value.

Q. How did Empire respond?

A. Empire provided the specific methodology it used to calculate the PPA replacement dollar value that is in the table provided as Exhibit D attached to Appendix B of the *Non-unanimous Stipulation and Agreement*. It is based on the capital cost of the wind projects and the amount of energy obtained through the current Elk River and Meridian Way wind PPAs.

Q. Which of these foregoing definitions is most favorable to shareholders?

A. Empire's methodology provides the definition that would shift the most risk from shareholders to customers because it would put more benefits into the MPPM calculations.

Q. Is valuation of the PPA replacement value consistent with the RES statute?

A. Only if it is the least-cost renewable resources available at that time.

Q. Regarding how to calculate the PPA replacement value for the MPPM, what do you recommend that the Commission do?

A. I recommend that the Commission completely remove the PPA replacement value from the MPPM.

Q. Why?

A. Current SPP market prices are less than the cost Empire pays for the generation from its Elk River and Meridian Way wind PPAs, which results in losses each

[65] Data request 295.

month that get passed on to customers, i.e., they cost customer more than if Empire did not have those PPAs. It is unlikely that those PPAs will earn a positive margin any time before they end. Just ending these contracts would save Empire's customers around $1 million a month. This saving has nothing to do with the wind projects. It has everything to do with the end of uneconomic PPAs.

These uneconomic PPAs are currently Renewable Energy Standard ("RES") resources, but they are considered to be no cost RES resources because Empire entered into them before September 30, 2010.[66]

While Empire will still have RES requirements it must satisfy when these PPAs end, using the wind projects to meet those RES requirements then is a byproduct of building these wind projects, not why Empire built them. Empire has consistently said that these wind projects are in the customers' best interest because the revenues from the SPP market they will generate will be greater than their cost. Therefore, there should not be a PPA replacement value in the MPPM.

However, as I said in my direct testimony, if there is an amount credited to the wind projects for RES, it should be for the lesser of the least cost renewable source at that time and only for the MWh of renewable energy necessary to meet Empire's RES requirement at that time.

Q. Will the cost of the wind projects be the least cost alternative to meet the Missouri Renewable Energy Standards ("RES") when energy is no longer available from the current PPAs?

A. I do not know. Energy from the Missouri wind projects, Kings Point and North Fork, may be the least cost since Missouri renewable resources count more towards satisfying the RES requirement. However, this should be determined when that RES energy is needed, not now.

[66] 20 CSR 4240-20.100 Electric Utility Renewable Energy Standard Requirements, Section (5)(A).

Q. Does Empire need all of the energy produced by the current Elk River and Meridian Way wind PPAs to satisfy the RES?

A. No it does not. Therefore, if t the PPA replacement value is included in the calculation of the MPPM, it should be only for the amount of resources needed and not based on the energy produced by Elk River and Meridian Way.

Q. Would you summarize your position regarding the MPPM?

A. The MPPM provides a benefit to customers that are taking on the risk of Empire's wind projects. The Commission recognized in its Report and Order that all of the variables in the MPPM could change[67] and that future conditions of the MPPM are not locked in.[68] Therefore, I recommend the Commission adopt the modifications to and clarifications of the MPPM I present in my direct testimony and here.

<u>Fuel Adjustment Clause</u>

Q. How is Empire requesting its FAC to be modified due to the wind projects?

A. The Empire exemplar tariff sheet shows the addition of "Net wind revenues from North Fork Ridge, Neosho Ridge, and Kings Point" in the definition of OSSR.[69]

Q. Is "Net wind revenues from North Fork Ridge, Neosho Ridge, and Kings Point" defined in the exemplar tariff sheets?

A. No. However, if it meant only the SPP market revenues from the wind projects, the current tariff language would suffice. Therefore, Empire must intend for this to mean more than just revenues from the SPP market.

[67] Page 28.
[68] Page 29.
[69] Exemplar tariff sheet 17n.

Q. Is including a definition of "net wind revenues" in the FAC tariff sheets critical?

A. Yes. If this phrase is included in the FAC tariff sheets, what is included in "net wind revenue" could change from filing to filing and could be inconsistent with the revenues that were included in Empire's FAC net base energy cost calculation.

Q. What Empire witness provided testimony regarding the wind revenues that Empire is requesting flow through its FAC?

A. Empire witness Aaron J. Doll provided testimony on the wind project revenues that Empire is requesting be included in Empire's FAC. Mr. Doll testified market revenue generated from each wind project should be treated exactly as Empire treats the revenue from the rest of its generation assets.

Q. Do you agree with Mr. Doll regarding the treatment of market revenues from the wind projects?

A. I agree that revenues from the SPP energy market should be treated exactly as Empire treats its SPP energy market revenue from the rest of its generation. However, in his testimony, Mr. Doll extends his definition of market revenues to include paygo, tax equity distributions, RECs, and PTCs.[70]

Q. Do you agree with Mr. Doll that the definition should be expanded to include these revenue streams?

A. No. Paygo, tax equity distributions, and PTCs should not be included as "market revenues" in the FAC. Revenue from the sale of RECs should be included in the FAC, just as the revenue from the sale of RECs from Empire's two wind PPAs are included in its FAC.

[70] Page 16.

Q. Are there market sources for any of these revenues?

A. No. As Mr. Doll testifies, paygo will be paid by the tax equity partners.[71] PTCs are not revenue[72] and RECs revenue is obtained from a variety of sources, but no one market.

Q. What about the tax equity distributions?

A. Mr. Doll merely states that tax equity distributions are a necessary component of the tax equity structure, and points to Todd Mooney's testimony for a full description of tax equity distributions.

Q. Did Mr. Mooney define tax equity distributions in his testimony?

A. No, he did not. A search for "tax equity distributions" in his testimony reveals that he did not even mention them.

Q. Does Empire have any generation assets for which it receives tax equity distributions, paygo revenues, or PTCs?

A. Not that I am aware of.

Q. If properly defined, should these be allowed to flow through Empire's FAC?

A. No. Something as nebulous as tax equity distribution should not be allowed to flow through Empire's FAC.

OPC witness John Riley provided direct testimony on the proper treatment of paygo revenues. PTCs are tax credits, not revenue sources. Empire has stated that it will provide the value of the PTCs to its customers. PTCs are not a revenue source nor are they fuel, purchased power, or transportation cost, and should not flow through Empire's FAC. A value for PTCs should be included in Empire's revenue requirement, and the actual PTC value should be tracked for treatment in Empire's next general rate case.

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[71] Page 16.
[72] Page 17.

REC revenues are currently flowing through Empire's FAC and the revenues that Empire receives for the RECs from these wind projects also should flow through its FAC. No additional language is necessary for these revenues to flow through Empire's FAC.

Q. Why is Empire proposing paygo, tax equity distributions, RECs, and PTCs flow through its FAC?

A. Mr. Doll states that including these in its FAC will ensure timely pass through of benefits to Empire customers as presented in EO-2018-0092.[73]

Q. Did the Commission approve passing paygo, the value of PTCs or tax equity distributions through Empire's FAC in Empire's customer savings plan case, Case No. EO-2018-0092?

A. No. There is no mention of the FAC in the Commission order in that case.

Q. Is passing these revenues through Empire's FAC the only way to ensure timely pass through of benefits to Empire's customers?

A. No. The best way to ensure timely pass through of these benefits is to include a normalized amount of revenue for them in Empire's revenue requirement, and then track the difference. If the normalized amount is accurate, then there should be little variation and any additional benefits can be provided to customers in Empire's next general rate case.

Q. Did Empire include a normalized amount for these revenue streams in its revenue requirement in this case?

A. It did include an amount for the value of the PTCs and the RECs. I could not find an amount for paygo.

[73] In the Matter of the Application of The Empire District Electric Company for Approval of Its Customer Savings Plan.

Q. Are the amounts that Empire included reasonable estimates?

A. The value of a PTC is set by the federal government. Therefore, the PTC value to be included in the revenue requirement should be straight forward.

As for revenue from the sale of the wind project RECs, Empire is estimating revenue of *** ____________ *** for RECs generated by the wind projects which is the same amount that Empire is paying for the REC. Empire is estimating revenue of *** ____________ *** for RECs from its two wind PPAs for which are included in the cost of each MWh generated.

Q. Is this a realistic price for RECs?

A. No. A search on the internet provides that Usource Energy states that over the past 15 months, the cost of a Green-e Certified REC has risen from roughly $1 per REC to almost $8 per REC.[74] While the value of a REC is tied to the renewable resource, where it is located and when the MWh was generated, the *** ____ *** per REC Empire is estimating seems extremely low.

Q. What is the impact of using a low value for Empire's revenue requirement, and then tracking that amount against actual revenues?

A. Because this is revenue, putting a low amount that Empire's revenue requirement means higher rates for customers, with Empire getting to use the excess until it is returned to customers in its next rate case, *i.e.*, in the short-term it gives Empire more cash on hand and customers less cash in their pockets.

Q. Should an amount for paygo be included in Empire's revenue requirement?

A. Yes. Paygo is touted as one of the benefits to Empire from its agreement with its tax equity partner. An estimated amount is included in its demonstration of how

[74] https://www.usourceenergy.com/blog/recs-are-expensive-now-what-alternatives-to-meeting-your-sustainability-metrics/.

the MPPM will work. An amount for this revenue should be included in Empire's revenue requirement, and paygo should not flow through Empire's FAC.

Empire has stated its concern for its customers, and Mr. Wilson has testified that in this case Empire undertook significant actions to lessen the bill impacts of this rate case on customers. However, I could not find that Empire included an amount for paygo in its revenue requirement. Doing so would have reduced Empire's revenue requirement, and lessened the rate impact on Empire's customers.

Q. What amounts did Empire estimate for paygo in its demonstration of the MPPM?

A. In Exhibit B of Appendix B of the *Non-Unanimous Stipulation and Agreement* the Commission approved in Case No. EA-2019-0010, Empire estimated paygo[75] would generate revenues of more than $5 million a year. In the updated version of the MPPM, Empire estimated it at $10 million a year.

Q. What would be the impact on Empire's revenue requirement if paygo was included and the included price for RECs was higher?

A. Both would cause Empire's revenue requirement to be lower, lessening the impact of this rate case on its customers.

Q. Do not including these paygo and REC revenues affect the base of Empire's FAC?

A. I searched Empire's workpapers and I could not find that, even though Empire is requesting paygo be included in its FAC, it included paygo as a revenue reduction to its FAC base. So, not including paygo in its FAC would not impact its FAC base.

[75] Paygo is netted with tax equity cash distribution and titled "Tax Equity Expense (Credit)" in Exhibit B.

However, Empire's FAC base would need to be recalculated without the value of the PTCs and with a higher revenue stream from the sale of RECs.

Q. How would it impact Empire's customers if paygo is not included in the calculation of the FAC base, but paygo does flow through Empire's FAC as Empire is proposing?

A. Customers would only realize 95% of paygo through Empire's FAC. The rest (5%) should go into a regulatory liability account if it is to be returned to customers because of the MPPM. Or perhaps Empire intends to keep the 5%. Empire has not stated how it would treat the 5% of the revenues that, because of the design of its FAC, would not flow through its FAC to its customers.

Q. Are there any other modifications in Empire's proposed FAC tariff sheets upon which you would like to comment?

A. Yes. The Commission should not approve the language Empire is requesting be added on exemplar tariff sheet 17i that would allow a variance from <u>any</u> provision of this FAC Rider for "good cause shown."

Q. Why not?

A. My understanding of the FAC statutes, informed by counsel, is that that an FAC can only be changed in a general rate case. Including this provision in the FAC tariff sheet on its face would allow the Commission, upon request by Empire, to change its FAC between general rate cases.[76]

Q. What is your recommendation regarding Empire's request to provide a different FAC calculation for customers on a time-of-use rate?

A. It should not be approved in this case. Empire has not shown that this is needed. The time-of-use rate requested by Empire is limited to a very small total number of

[76] Section 386.266.5 RSMo.

participants. Empire should gather data from participants if it wants to attempt to show in its next general rate case why it needs this FAC change.

Q. Do you have any suggestions regarding Staff's recommended FAC-related reporting requirements?

A. Yes. First of all, the OPC and other parties to this case should also receive the notices and be provided with a copy of this additional reported information.

The last of Staff's recommendations is necessary due to revisions to the Commission's FAC rule 20 CSR 4240-20.090 that became effective on January 30, 2019. One of the changes in the section related to quarterly surveillance report submissions is that, for electric utilities with foreign ownership which do not make 10-K filings with the Security and Exchange Commission ("SEC"), the deadlines for the submission of surveillance reports are to be set in general rate proceedings. Empire is a wholly-owned, indirect subsidiary of Algonquin Power & Utilities Corp., a foreign company that does not make 10-K filings with the SEC. Therefore, the Commission needs to set the deadline for the submission of the quarterly FAC surveillance reports. I found no recommendation in the Staff's reports for when these submissions should be made.

Q. Did Empire propose deadlines for these surveillance report submissions?

A. I could not find a proposal in Empire's direct filing.

Q. What do you recommend?

A. I recommend the Commission order the following deadlines for Empire's quarterly FAC surveillance reports:

Quarter Ending:	Submission deadline
March 31	End of May
June 30	End of August
September 30	End of November
December 31	End of February

With the exception of one submission, Empire has provided its quarterly FAC surveillance reports by these deadlines since Algonquin acquired it.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.