Exhibit No. 204

OPC – Exhibit 204
Lena Mantle
Direct Testimony
File No. ER-2021-0312

Exhibit No.:	______________
Issue(s):	Asbury/Market Price Projection Mechanism/Fuel Adjustment Clause (FAC)
Witness/Type of Exhibit:	Mantle/Direct
Sponsoring Party:	Public Counsel
Case No.:	ER-2021-0312

DIRECT 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

October 29, 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 direct testimony.

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

Lena M Mantle

Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 29th day of October 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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DIRECT TESTIMONY

OF

LENA M. MANTLE

THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. ER-2021-0312

INTRODUCTION

What are your name and business address?

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

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

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

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the OPC.

Q. To what are you testifying?

A. I am testifying on three different issues. First, I provide support for the recommendations on recovery of the costs of The Empire District Electric Company's ("Empire's") Asbury plant provided by OPC witness Dr. Geoff Marke through a discussion of how, even though Empire is meeting the Southwest Power Pool ("SPP") reserve margin requirement, the retirement of its Asbury plant resulted in a worsening of Empire's resource adequacy and increased costs to Empire's customers. Second, I raise concerns with and recommend changes to the market price protection mechanism ("MPPM") that the Commission adopted in Case No. EA-2019-0010[1] ("CCN case") based on information that is now known,

[1] *In the Matter of the Application of The Empire District Electric Company for a Certificates of Convenience and Necessity Related to Wind Generation Facilities,* Case No. EA-2019-0010, Report and Order, effective June 29, 2019, p. 59.

but was estimated when the Commission adopted the MPPM. Third, I recommend modifications to Empire's fuel adjustment clause ("FAC").

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

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

Prior to being employed by the OPC, I worked for the Staff of the Missouri Public Service Commission ("Staff") from August 1983 until I retired as Manager of the Energy Unit in December 2012. During my employment at the Missouri Public Service Commission ("Commission"), I worked as an Economist, Engineer, Engineering Supervisor and Manager of the Energy Unit. After the Missouri Legislature passed Section 366.266, RSMo in 2005, enabling the electric utilities to request a fuel adjustment clause ("FAC"), I was instrumental in the development and application of the Commission's FAC rules and the FACs of the electric utilities in Missouri. I have provided testimony regarding FACs in numerous general rate cases, FAC rate change cases, and FAC prudence cases, both during my time on the Commission Staff and since my employment at the OPC.

I was an active participant on behalf of the OPC in the cases filed before this Commission by Empire regarding the planning and construction of the Kings Point, North Fork Ridge, and Neosho Ridge wind projects ("wind projects"). I provided testimony on behalf of the OPC in both the EO-2018-0092 and EA-2019-0010 cases.

Attached as Schedule LMM-D-1 is a brief summary of my experience with the OPC and Staff, and a list of the Commission cases in which I filed testimony, Commission rulemakings in which I participated, and Commission reports in rate cases to which I contributed as Staff. Attached as Schedule LMM-D-2 is the *Electric Utility Fuel Adjustment Clause in Missouri: History and Application*

Whitepaper that I wrote to provide background and a description on various aspects of the FAC in Missouri.

Planning Reserve Margin vs Resource Adequacy

Q. Why are you testifying about Asbury?

A. As provided in the direct testimony of OPC witness John Robinett, Empire made considerable investment in its Asbury plant to extend the life of the plant while meeting state and federal environmental standards. When Empire chose to retire the Asbury plant, Empires' customers had not received the full benefits of these improvements as promised. The purpose of my testimony is to describe the resource adequacy benefits of Asbury to Empire's customers that no longer exist and show that Asbury still had economic value when and after Empire retired it. OPC witness Dr. Marke uses this information in determining his recommendations regarding the recovery of Asbury costs.

Q. What is planning reserve margin?

A. Planning Reserve Margin, calculated as the percentage by which installed capacity exceeds peak demand, is a deterministic metric that produces a single value for the peak period of a single future season (typically summer or winter when electricity loads are higher). This metric has two inputs: resources and forecasted load.[2]

Q. What planning reserve margin does the SPP require of Empire?

A. The SPP planning criteria sets the planning reserve margin for Empire to be 12%.

[2] *Resource Adequacy Primer for State Regulators,* July 2021, page 6.

Q. What were Empire's SPP planning reserve margins after it retired its coal-fired Asbury generating plant?

A. The summer after retiring Asbury, Empire barely met the SPP planning requirement with a reserve margin for the summer of 2020 of 12.05%.[3] With the additional capacity from its wind projects, Empire's 2021 summer SPP planning reserve margin increased to 16.02%.[4]

Q. What do you know about Empire's planning reserve margin in the near future?

A. Because Empire is experiencing very little load growth and I am not aware of Empire adding any generation in 2022, I expect Empire's summer reserve margin to be nearly the same for 2022 as it was for 2021. However, SPP is implementing new accreditation policies for wind resources that will go into effect in the 2023 summer season that could change the capacity accreditation of Empire's wind resources.[5]

Q. What is resource adequacy?

A. Unlike reserve margin, which looks at a single point in time - the peak hour - and measures how much generation is available at that point in time, resource adequacy is the ability of the electricity system to supply aggregate electric power and energy to meet the requirements of consumers at all times, taking into account scheduled and unscheduled outages of system components. Resource adequacy is foundational for providing reliable electric service across all hours.[6]

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[3] *2020 SPP Resource Adequacy Report,* page 19.
[4] *2021 SPP Resource Adequacy Report,* page 22.
[5] *Resource Adequacy Primer for State Regulators,* July 2021, page 48.
[6] *Resource Adequacy Primer for State Regulators,* July 2021, page 6.

Resource adequacy for a vertically integrated utility means that the utility has the resources that it needs to meet its customers' needs at all times without depending on its regional transmission organization markets for energy.

Q. Has retiring Asbury affected Empire's resource adequacy?

A. Yes. However, with the exception of the outages during the winter storm in February 2021, Empire customers' needs have been met. Empire belongs to the SPP and has relied on other utilities' resources. However, on a stand-alone basis Empire does not have resources that can meet the needs of its customers every hour, even though it exceeds the SPP planning reserve margin requirement. The retirement of this dispatchable resource greatly decreased Empire's ability to meet its customer's needs with its own resources.

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

A. While their customers are likely to always have the energy they need, relying on the market exposes customers to high energy price risk. If a utility has adequate resources, the cost of extreme weather events such as the one which occurred in February 2021 will be significantly lower for those utilities that have adequate resource capacity. The generation resources of these utilities will provide revenue that offsets the cost of the energy at the load. Those utilities with inadequate resources will not have those revenues.

Generation resources are hedges to market prices. Some types of generation are better hedges against extreme market prices (dispatchable) than others (intermittent).

Q. How are generation resources hedges to market prices?

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

Dispatchable resources provide a hedge when the market price is greater than the cost for that resource to produce electricity. The benefit is the difference between the market price and the cost of producing the electricity. When market prices are high and the dispatchable resources are producing electricity, the dispatchable resources are a hedge against market prices because they are able to provide electricity at the time when market prices exceed the cost for that resource to produce electricity.

The difference is in the energy source. Dispatchable resources use fuel that is typically available upon demand. Intermittent resources provide benefits when their energy source—wind or light—is available.

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

A. Yes. Whatever resources were generating were hedges against market prices. However, dispatchable resources with on-site fuel were better hedges because they were available more hours.

Q. Why is this important in this discussion of resource adequacy?

A. Resources that are good hedges increase resource adequacy. Asbury was a dependable resource that Empire had updated at considerable expense to meet state and federal environmental standards. Its availability and its on-site fuel source made it a good hedge increasing the adequacy of Empire's resource portfolio.

Q. Would you generally explain the resource adequacy of Empires' current resources?

A. All of Empire's remaining generation resources have operating constraints reducing their resource adequacies in varying amounts.

Natural gas or oil is the fuel for 73% of Empire's capacity.[7] These resources are available for Empire to dispatch. Over half of Empire's natural gas generation is from efficient combined cycle ("CC") plants. When natural gas prices are low, as they were in 2020, these plants are reliable and inexpensive sources of electricity.

The rest of Empire's natural gas generation resources are combustion turbines that, while quick to start up and run, can be expensive to run for long periods of time even when the price of natural gas is low. They can quickly respond to a need but cannot be relied upon to generate for long periods of time.

Natural gas is not stored on site. Empire has firm natural gas transportation for much of its natural gas fired capacity. Typically, Empire can rely on delivery of natural gas to these generation plants as it is needed. However, natural gas delivery to these generation facilities may be interrupted due to other demands on the pipelines as demonstrated during the February 2021 extreme weather event when Empire's customers desperately needed electricity to heat their home.

Less than 10% of Empire's accredited capacity is renewable resources. These are intermittent resources where Empire has little to no control over when these resources will provide energy for Empire's customers. This is reflected in the low SPP capacity accreditation for intermittent resources in comparison to their maximum design capacity. The rated turbine capacity of the newly added wind projects is approximately 600 MW. SPP only accredits Empire 30 MW for this 600 MW of wind. This reflects the resource adequacy of wind. The SPP's accreditation of these wind projects demonstrates that the SPP recognizes that wind resources

[7] The capacity referred to in this answer is Empire's SPP accredited capacity.

cannot be relied upon to provide electricity at their maximum capacity when customers need it.

Empire's remaining resources are fueled by coal. Coal plants typically maintain more than a 30-day supply of coal on site, and are inexpensive to run, but take time to ramp up their electricity output. However, with the retirement of Asbury, Empire is not the majority owner of any of its coal resources. In an October 26, 2021 resource planning meeting, Empire informed Staff, OPC, and other parties that *** ______________________________ *** These are decisions to which Empire has little to no input or control but which impact the adequacy of Empire's generation resources available to meet its customers' needs. Empire does not make the dispatch, management, and inventory decisions for these plants.

Asbury was a low cost, dispatchable resource with the ability to have an inventory of fuel on site. When it retired Asbury, Empire lost its only resource for which it had a stable supply of fuel and that it could dispatch based on its customers' requirements.

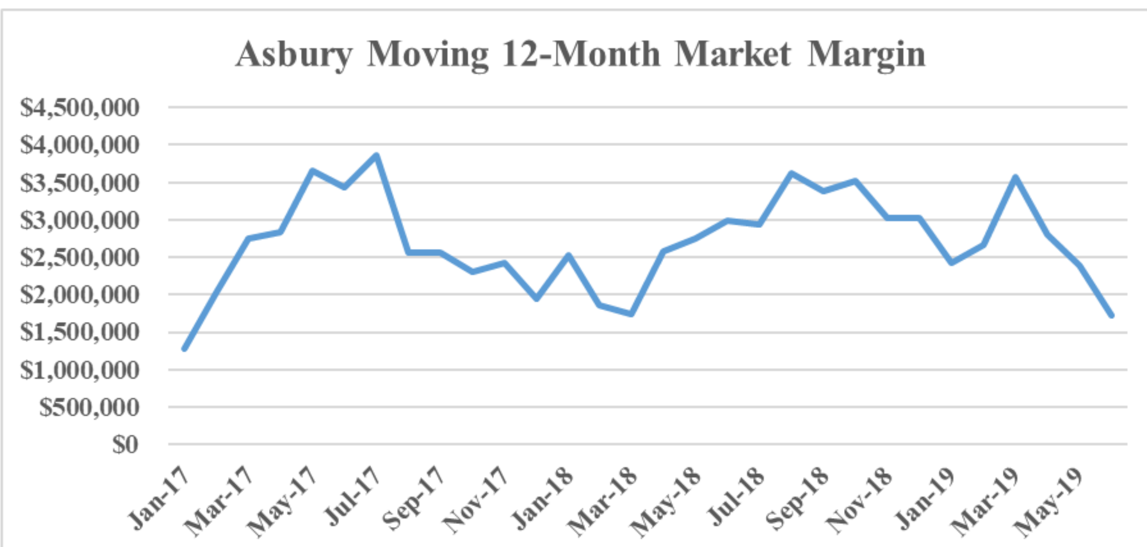
Q. Did Empire consider resource adequacy when it decided to retire Asbury?

A. I have not seen any documentation that Empire reviewed the impact of retiring Asbury on its ability to adequately meet its customers' needs. The modeling done by Empire always allowed Empire to purchase energy from the SPP to meet its load. It was not restricted to energy from its own resources.

Empire has continuously stated that it retired Asbury because keeping the plant running was uneconomic and its retiring of Asbury would lower costs to customers in the long run. In fact, Empire's "customer savings plan" first presented to the Commission in Case EO-2018-0092[8] is replete with references to how the wind generation would replace Asbury once it was retired. Asbury provided energy when <u>customers</u> needed it.[9] The wind generation that Empire touted as "replacing" Asbury provides energy when the wind is blowing irrespective of its customers need for electricity. If customers need electricity and the wind is not blowing, then Empire has to turn to other dispatchable resources or the SPP market. If the wind is blowing and customers do not need the energy, Empire must sell it to the market – sometimes at a negative cost.

Q. Was Asbury uneconomic in the SPP energy market when Empire retired it?

A. No. As the graph below shows, Asbury's market margin was positive, meaning the revenues Empire received from SPP for Asbury were greater than Empire's fuel costs to run Asbury, even in 2017 and 2018 when the decision was being made to retire Asbury.

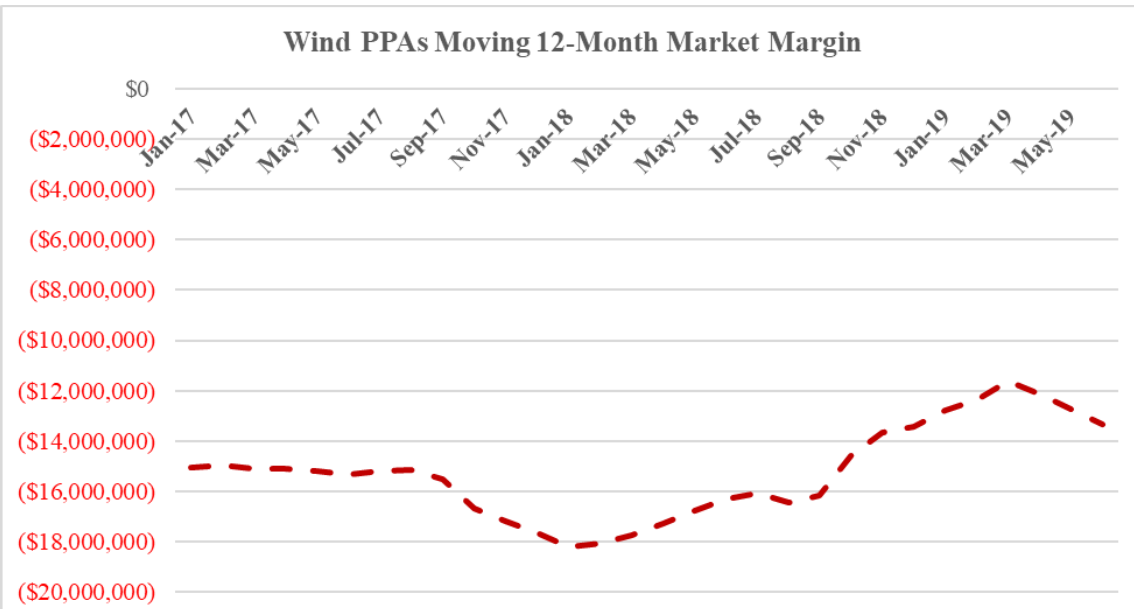


[8] *In the Matter of the Application of The Empire District Electric Company for Approval of Its Customer Savings Plan,* EO-2018-0092

[9] While Asbury did have unexpected forced outages, outages for maintenance were planned at times low cost energy was available from other resources and expected customer demand was low.

Q. Were all of Empire's other generating resources economic in the SPP energy market in 2017 and 2018?

A. No. The margins from the generation from Empire's two wind purchased power agreements ("PPA") were, and still are, consistently negative. The graph below shows the moving 12- month market margins for the same time period for the wind PPAs.



As shown in this graph, judged just on the market margin, the wind PPAs were drastically uneconomic at the same time the decision was being made to retire Asbury, even though Asbury was showing a positive margin.

Q. There is no fuel cost for wind is there?

A. No. However, there is a cost to customers for these wind PPAs that must be paid regardless of the market price when the wind is blowing.

Q. Would you summarize this section of your testimony?

A. Empire made considerable investment in its Asbury plant to extend the life of the plant while meeting state and federal environmental standards. When Empire chose

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to retire the Asbury plant, Empires' customers had not received the full benefits of these improvements as promised. Asbury was still generating a positive margin from the SPP IM and, by being a good hedge against market prices, it increased the resource adequacy of Empire's resource portfolio. For these reasons, the Commission should adopt the Asbury cost recovery recommendations of OPC witness Dr. Marke.

<u>Market Price Protection Mechanism</u>

Q. What is the Market Price Protection Mechanism?

A. In the wind projects CCN case EA-2019-0010, Empire, Staff, Missouri Energy Consumers' Group ("MECG"), Renew Missouri, and the Missouri Department of Energy ("DE") filed a *Non-unanimous Stipulation and Agreement* recommending the Commission grant Empire a Certificate of Convenience and Necessity ("CCN") with numerous conditions, one of which was a market price protection plan.[10] The Commission granted the CCN with conditions, including the market price protection mechanism ("MPPM"). In its *Report and Order,* the Commission stated the MPPM was designed to mitigate risks to customers of the revenues from the wind projects not being as expected, and added a layer of protection for the low probability events related to the supply side generation.[11]

Q. Were you part of the drafting and design of the MPPM?

A. Initially I was. However during the drafting process it became clear that the MPPM the other parties were agreeable to would leave customers almost entirely exposed to all downside risk while Empire and the tax equity partners were guaranteed a profit. The OPC told the parties that it could not agree to such a MPPM and we were excluded from negotiating the final design of the MPPM.

[10] OPC objected to the non-unanimous stipulation and agreement on April 12, 2019, *The Office of the Public Counsel's Objection to the Non-Unanimous Stipulation and Agreement Filed April 5, 2019*
[11] Page 49.

Q. What is your understanding of why the MPPM was developed and what the MPPM does?

A. It was clear that Empire was not building its new wind projects to meet customer load. Empire wanted to build these wind projects and recover the cost plus a return on the cost of the wind projects. It promoted these wind projects as a good deal for customers based on its belief that the revenues received from these wind projects would be greater than the costs to its customers resulting in lower customer bills. Because this was speculative generation built to "beat the market," not generation built to meet a need, some of the parties in the case and Empire negotiated the MPPM to cover the possibility that the wind projects would not provide more benefits than the costs in the first ten years they operated.

The MPPM tracks the benefits provided to the customers from the wind projects and the costs of the wind projects paid for by the customers during the first ten years of the projects. The MPPM in the Stipulation and Agreement requires a shared the risk of the first $52.5 million of losses between Empire and its customers. If, after ten years, losses were greater than $52.5 million, the parties could propose to the Commission alternatives for the treatment of the amounts greater than $52.5 million that Empire's customers will have already paid.

Q. Based on your review, do you have any concerns about the MPPM?

A. I support the goal of providing customers protections, but I am concerned with the details of the MPPM.

Q. What are your concerns about the details of the MPPM?

A. Appendix B to the *Non-unanimous Stipulation and Agreement* defines the wind revenue requirement ("WRR") for the MPPM to include the following costs: 1) operation and maintenance, 2) labor, 3) tax equity payments/credits, 4) property taxes, 5) return on and of, and 6) income taxes.

The MPPM should include all of the costs customers will be paying. It does not, but should, include renewable energy credit costs. *** ____ *** The other cost that I am aware of that is not included in the MPPM, but should be included is the cost to customers of Empire's election of plant in-service accounting ("PISA") for the wind projects.

Q. Do you have concerns with any of the WRR components listed in Appendix B?

A. Yes. My understanding is that what Empire categorized as tax equity payments/credits is actually the aggregate of a benefit (paygo) and a cost (tax equity distributions).

Q. What is paygo?

A. My understanding is that this is a payment made to the wind project holding company from the tax equity partner that is passed on to Empire when the number of production tax credits achieved by the wind project is greater than a pre-determined amount. Empire witness Todd Mooney defines paygo in footnote 9 on page 14 of his direct testimony as:

> Contingent Contributions (referred to as "Paygo") represent additional contributions of cash by the tax equity partners to Empire Wind Holdings, LLC based on actual production in excess of a threshold. Paygo contributions received by Empire Wind Holdings, LLC are distributed to Empire and hence reduce the cost of service to customers.

Q. What are tax equity distributions?

A. Tax equity distributions are the partnership cash distributions that will be made by the wind holding companies to Empire and the tax equity partners.[13] *** ____

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[12] Renewable energy credits, are tradable, non-tangible commodities that represent proof that one MWh of electricity was generated from a renewable energy resource and was then fed into the shared system of power lines that transport energy. (https://energywatch-inc.com/renewable-energy-credits-recs-explained/)

[13] Empire response to OPC data request 8010 in case EA-2019-0010.

______________________________ *** The MPPM shows the total cash distribution as estimated to be paid out by the wind holding companies with an adjustment for the distribution paid to the tax equity partner.

Q. Why do combining the tax equity distributions and paygo in the calculation of the WRR concern you?

A. They do not reflect what will actually transpire. Paygo will be a benefit. If SPP revenues are greater than the costs in the years when some of the cash distribution is provided to the tax equity partners, then this will be a decrease in costs and benefits. Combining the paygo and tax equity distributions as a cost obscures information on both.

Q. How should the MPPM be modified to address your concerns?

A. To address the tax equity payments, the MPPM should be modified to reflect the actual amounts that will flow to Empire. *** ______________________________ _*** The MPPM should reflect only costs and benefits to Empire customers.

To get a clearer picture of actual costs, paygo should be tracked separately as a benefit. In his direct testimony in this case, OPC witness John Riley recommends that an estimated amount of annual paygo be included in Empire's revenue requirement. Between rate cases the difference between the estimated paygo and the actual paygo should be tracked with Empire's customers receiving any extra benefits or reimbursing Empire if the estimated benefits were too high through rates set in Empire's next rate case. Paygo is not a fuel, purchased power, or transportation related revenue and should therefore not be included in Empire's FAC.

Q. What benefits are included in the MPPM described in Appendix B?

A. The only benefit shown in the MPPM are SPP integrated market ("IM") revenues.

Q. Are there other benefits associated with the wind projects?

A. Yes, in addition to paygo described above and the SPP integrated market revenues, there are revenues from the sale of the wind projects' RECs, and production tax credit values, both of which should be included in the MPPM.

Q. Why not just include net REC revenues instead of showing the costs of RECs separate from the revenue from selling RECs?

A. There is a fluctuating market for RECs with prices influenced by supply and demand. There will be a flood of wind RECs with all of the wind generation that is being added in the SPP. Empire may choose to hold on to its RECs waiting for an increase in the price or may choose not to sell RECs because the price is lower than the cost waiting for market values to increase.

Since the timing of the purchase and the sale of RECs may be different, they should be tracked separately.

Q. How should Empire's customers realize the benefits of the SPP IM and REC revenues from the wind projects?

A. SPP IM revenues from Empire's other generation currently flows through its FAC as does the revenue from the sale of RECs from the current wind purchased power agreements ("PPAs"). Therefore the SPP IM revenues and the cost and revenues from RECs should flow through Empire's FAC. This will result in most of these benefits flowing back to customers between general rate cases. However, to assure customers receive all of the revenues from the wind projects as measured by the MPPM, either 100% of the SPP IM and REC revenues should flow through Empire's FAC or the difference from what is actually received and what is returned to Empire's customers should be tracked and netted until Empire's next general rate case. Any resulting regulatory liability would returned to the customers in that next rate case, amortized over a time-period consistent with the tracking. Likewise, any resulting regulatory asset would be amortized, and recovered from Empire's customers over a time period consistent with the tracking.

Q. Why should production tax credits be included in the MPPM?

A. It is unknown when or how the tax credits will be utilized, and whether, when utilized, will result in revenue, or a lower tax liability. Nonetheless, Empire has stated its willingness to provide to customers this known value. This is a benefit and should therefore be included in the MPPM.

Q. How should Empire's customers realize the production tax credit benefits?

A. Production tax credits ("PTCs"), while a benefit, are not a realized revenue. Empire has committed to providing a revenue credit commensurate with the values associated with the PTCs Empire gets. PTCs are not directly tied to fuel, purchased power, or transportation, so no portion of these benefits should flow through Empire's FAC. An estimated amount of these revenues Empire will be providing should be included in its revenue requirement used for designing its rates, and the differences between the estimated revenue and the achieved revenue should be tracked. If the result is a regulatory liability, it should be returned to Empire's customers, or, if it is a regulatory asset, it should be amortized and the amortized amount included in Empire's revenue requirement for designing Empire's rates in its next general rate case.

Q. Other than more specificity regarding the costs and benefits that should be included in the MPPM, do you have any other concerns regarding the MPPM?

A. Yes. Appendix B states that the rate base cost and carrying cost will be calculated every year. In addition, Exhibit A of Appendix B states that a Missouri jurisdictional allocator be applied in year 10 to the cumulative Annual Sharing Value if it is negative. It does not specify how the jurisdictional value is to be calculated.

Q. Why is calculating the rate base cost and carrying cost every year a concern?

A. The MPPM is supposed to compare the costs and the benefits of the wind projects to Empire's customers. The MPPM that is shown in the Stipulation and Agreement shows the wind projects' rate base and return changing every year. However, in practice, that rate base and return paid by the customers will only change each time when new Empire rates go into effect.

Q. How do you recommend that the wind projects' rate base cost and carrying cost be accounted for in the MPPM?

A. The MPPM should track the actual rate base cost and carrying costs paid by Empire's customers, meaning these costs should remain constant between Empire rate cases.

Q. How do you recommend the MPPM jurisdictional allocation factor be calculated?

A. The wind projects generate energy; therefore, the energy jurisdictional allocation factor should be used in the MPPM.

Q. Do have concerns that would require more substantial modifications to the MPPM?

A. Yes.

Q. What are they?

A. As I previously stated, these wind projects were not built because Empire needed more generation to meet the needs of its customers. They were not built in an effort to increase Empire's resource adequacy to serve its customers. The wind projects are a speculative venture for which Empire is asking its customers to not only pay for, but also to provide Empire with a return on.

Since the Commission issued its order in the CCN case more than two years ago, there is more certainty on some aspects of the wind projects. The most critical being that the actual cost of the wind projects, due to many factors, is almost *** ____ ***Empire's revenue requirement due to the wind projects.

At this time the greatest uncertainty regarding the wind projects is the revenues that they will generate. The direct testimony of Empire witness Frank C. Graves shows how the projections used by Empire in its planning processes through the years have consistently over-projected market prices which are key to the benefits that will be realized by the customers.

In addition, as provided in the testimony of OPC witness Dr. Geoff Marke, there is considerable uncertainty about how the presence of gray bats in the area of the Kings Point and North Fork Ridge wind projects will affect the availability of the wind turbines to generate electricity.

At this point, the risk for Empire is low and the risk for the customers is high. Customers will pay Empire for the projects. This is very likely. The benefits the customers will receive are the great unknown. The MPPM should be modified to balance the risks of Empire and its customers.

[14] Todd Mooney Direct, page 5, cost estimates as of March 30, 2021.

Q. Do you know how this increase in the cost of the wind projects impacted the MPPM examples that are in Appendix B of the *Non-unanimous Stipulation and Agreement*?

A. No, not specific to the change in cost. However, Empire provided on October 19, 2021, in response to OPC data request 8075, Excel spreadsheets of an update of the Wind Data Sheet, the PPA Replacement Value, and the P50 Mid Market Price Market Protection Provision[15] of Appendix B of the CCN *Non-unanimous Stipulation and Agreement*. This update included changes in the cost of the Wind projects, increases in the PPA replacement value and decreases in the SPP market revenues.[16] The updated analysis, shows a ** ____________________ ** meaning Empire is now estimating, with its updates, that the costs, over the first ten years of the wind projects, will be greater than the benefits. For the MPPM, as shown in the *Non-unanimous Stipulation and Agreement*, the estimated cumulative annual wind value in year ten was a positive $145 million meaning that, at that time given Empire's inputs and assumptions, benefits were estimated to be $145 million greater than cost over ten years.

This was a swing of ** ____________ **, which demonstrates the risk of these wind projects to Empire's customers.

Q. What changes do you recommend the Commission make to the MPPM?

A. I recommend the following changes:

1. The cumulative Annual Wind Values should include interest at the same rate that is provided on customer deposits;
2. An energy jurisdictional allocator be applied to each year's annual wind value;

[15] Exhibits B, C, and D respectively of Appendix B.
[16] Empire also included REC revenues and PTC benefits in its Wind Data calculation that were not shown or mentioned in Appendix B to the Stipulation and Agreement in the CCN case.

3. A cap of $26.25 million losses accumulated over the first ten years for Empire's customers; and
4. No "PPA replacement" benefit be included in the MPPM.

Q. Why do you recommend that the cumulative Annual Wind Values include interest?

A. This is a ten-year mechanism with customers not seeing any relief from losses until after year ten. There will be losses in the first years because that is when the wind projects rate base is the highest. It is also when energy market prices are estimated to be the lowest. Therefore it is most likely that the wind projects will show benefits greater than costs in the later of the ten years. Without including interest, the dollar of profit in year ten is the same as the dollar of losses in year one. Yet had the dollar in year one earned even minimal interest, it would have been greater than the dollar in year ten. Including interest values the customers' funding of the losses in the early years of the MPPM.

Q. Why do you recommend that an energy jurisdictional allocation factor be applied annually?

A. Jurisdictional factors change over time. The jurisdictional factor in year one of the MPPM could be much different from the jurisdictional factor in year ten due to customer growth and changing usage characteristics. Applying jurisdictional allocation factors annually will more accurately tie the costs Missouri ratepayers paid for to the benefits they received in that year. Annual Wind Values are calculated. Annual jurisdictional factors should be applied to these values.

Q. The MPPM provides that the jurisdictional factor used will be based on the jurisdictional allocation ratios of Empire's prior rate case. Do you agree with this approach?

A. No. Energy jurisdictional allocation factors are simply the amount of energy for each jurisdiction divided by the sum of the energies of all the jurisdictions. It is not a difficult or complex calculation. It should be done for each year's Annual Wind Value.

Q. Why do you recommend that the limit of no more than $26.25 million of wind projects losses at the end of the ten-year MPPM be moved from Empire's shareholders to its customers?

A. As shown in the difference in the estimate of the cumulative annual wind values from the CCN case and Empire's response to OPC data request 8075 provided on October 19, 2021, the risk to Empire's customers is great over these ten years. At the same time, Empire is projecting that it will see a return on equity on these wind projects of $295 million. There is little to no risk to Empire surrounding this amount. If Empire does not recover the $295 million from its customers, it can come in and ask for more revenue from its customers to make sure that it earns this return.

Limiting the amount of losses Empire's customers would be required to cover reduces their risk. If Empire is correct in its projection of the net profit of these wind projects that it made in its CCN case, the cap will not matter and the MPPM will simply be a tracking exercise.

A less attractive alternative would be to split the amount of losses at the end of the ten years. While this may seem to evenly split the risks of the wind projects, it would not. Empire would still earn a return on the wind projects (reducing its risk) and its customers would be covering the losses in the early years (increasing their risk).

Q. Why do you recommend the MPPM be changed to remove the power purchase agreement replacement value in the MPPM?

A. These wind projects are not replacing Empire's current wind PPAs. Empire built these wind projects to make money, not to replace its wind PPAs. In fact, Empire consistently has characterized these wind projects as replacing coal-fired generation with wind generation. The wind projects were built to earn a return for shareholders with a potential for lower customers' bills over twenty years.

Q. Why did Empire enter into its existing wind power purchase agreements?

A. Empire entered into the wind PPAs because, at the time Empire was considering entering into these PPAs, Empire's modelling predicted the PPAs to be cost effective resources to meet its customers' needs over the next 20 years. At the time Empire was also adding coal generation to its available resources, the addition of the wind PPAs provided diversity to its generation resources. After Missouri adopted renewable energy standards ("RES") in 2008,[17] these PPAs provided Empire with more than enough energy to meet the RES, not only in the early years of the RES when the RES required the investor-owned utilities to generate 2% of their needs with renewables but also through the time when they needed to meet 15% of their customers' electric usage with renewables.

Now in 2021 with the SPP IM the wind PPAs are costing ratepayers between $1 million and $2 million a month. Since the IM market started, the wind PPAs only had a positive margin two months soon after the market started. The only economic benefit to the customers from these wind PPAs is that they do not have to pay for additional resources to meet the Missouri RES. Yet they are costly electric energy and capacity resources.

[17] Missouri Revisor of Statutes - Revised Statutes of Missouri, RSMo Section 393.1020

Q. Will Empire be able to use the wind projects to satisfy the requirements of the renewable energy standard when its current power purchase agreements expire?

A. If the wind projects are certified by the Division of Energy, Empire will be able use them as RES resources.

Q. Is there an alternative to your recommendation of not including the replacement value of the PPAs in the MPPM?

A. Yes. Instead of a PPA replacement value based on the amount of generation of the current PPAs, a benefit could be included in the MPPM equal to the lesser of the least-cost manner of meeting the RES at the time renewables are needed or the portion of the wind projects revenue requirement consistent with the RES requirement. The RES requirement of the wind projects would be the RES MWh needed after taking into account the energy generated at Empire's Ozark Beach Dam. The wind projects benefit calculation would also take into account the 1.25 multiplier for energy generated in Missouri.

Q. Have you estimated the impacts of your recommendations on the MPPM cost/benefit estimate that Empire provided in response to your data request number 8075?

A. Empire's MPPM, when updated assuming a rate case every four years to reset rate base, a Missouri jurisdictional allocation factor of 0.88, RES benefit calculated as a portion of the wind project revenue requirement, and accounting for interest at 3.25%, provides the following estimates:

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The $130 million that Empire would be required to return to its customer is a large amount of money. It would be a large amount <u>that customers would have already paid</u>. However, it is less than 45% of the return that Empire's customers would have paid on these wind projects. It is also important to remember that at the end of year ten customers would have already paid this amount because Empire had represented to the Commission that these wind projects would be beneficial to its customers.

If in the alternative, the losses were split 50/50, Empire would return to customers ** ______________ ** of the return customers had already paid to Empire.

Q. Do you have any other recommendations regarding the MPPM?

A. Yes. The Commission should require the submission of monthly reports that itemize the costs and the benefits included in the MPPM along with the cumulative value of costs and benefits that are being tracked for amortization in the next rate case.

Q. Would you summarize this section of your testimony regarding the MPPM?

A. The MPPM is a mechanism that compares the costs and benefits of the wind projects. As such a mechanism, it should include all costs and benefits. Based on the shift in the estimates of the outcome of the MPPM, the risk of costs being greater than benefits in the first ten years should shift away from the customers at the end of year ten, to Empire.

I am not requesting that the Commission find Empire imprudent and disallow costs, I am asking the Commission to make modifications to the MPPM. If Empire's analysis and projections are correct, my recommended changes are nothing more than tracking. I recommend that the Commission modify the MPPM to provide Empire's customers surety if time shows that Empire's modeling and assumptions were inaccurate.

Q. Would you summarize your recommendations regarding the MPPM?

A. The following are my recommendations:

1. The MPPM should include <u>all</u> costs and benefits as paid and received by Empire's customers
   - Costs as included in revenue requirement remain the same until revenue requirement is changed;
   - Include the cash distributions to Empire;
   - Include PISA costs;
   - Separately identify paygo as a benefit; and
   - Separately identify REC costs and revenues.
2. Estimated benefits of paygo and PTCs should be included in Empire's rate case revenue requirement with tracking mechanisms to reconcile to actuals in Empire's next rate case.
3. SPP IM revenues and REC revenues should be included in Empire's FAC with tracking mechanisms to reconcile to actuals in Empire's next rate case.
4. Interest should be paid on the Annual Wind Values.
5. Energy jurisdictional allocation factor should be applied each year based on the energy usage of all jurisdictions for that year.
6. Cap of $26.25 million on losses absorbed by customers.
   - Alternative would be to split losses 50/50.
7. No PPA replacement value in MPPM.

- Alternative would be to include a benefit equal to the lesser of the least-cost manner of meeting the RES at the time renewables are needed or the portion of the wind projects revenue requirement consistent with the RES requirement.

I have attached as Schedule LMM-D-3 a description of the revised MPPM with changes I am recommending.

<u>OPC's Recommended Modifications to Empire's FAC</u>

Q. What modifications to Empire's FAC do you recommend that the Commission order?

A. I recommend the Commission modify Empire's FAC to:

1. Include language that would allow the mitigation of the impact of extraordinary net fuel and purchase power costs;
2. Explicitly prohibit recovery of retirement and/or decommissioning costs related to the retirement of a generation plant;
3. Explicitly prohibit recovery of fuel and purchased power costs for research and development;
4. Update the percentage of SPP costs recovered; and
5. Include the same percentage of SPP transmission revenues associated with the SPP transmission costs recovered.

Q. Why are you recommending that Empire's FAC be modified to accommodate extreme cost changes?

A. The extended freeze in mid-February 2021 resulted in increases in fuel, purchased power and market revenues that, if passed through Empire's FAC would have had a tremendous impact on its customers' ability to pay their electric bills. The restriction by statute that FACs can only be changed in rate cases limited the remedies available in this situation. Even so, the utilities are looking at different ways to recover their winter storm costs.

The utilities' FACs should be modified to provide clarity to the companies, their customers, and the Commission for how this type of sudden, sharp change in costs will be handled in a manner that is affordable to customers while still allowing the utilities cost recovery with an opportunity for the Commission to review the prudency of those extraordinary costs.

Q. Do you have specific language that you are recommending be added to Empire's FAC tariff sheets?

A. I recommend the following language for recovery of extraordinary costs:

> When extraordinary net costs have been incurred in an accumulation period, for good cause the Commission may allow (after opportunity for any party to be heard) the recovery period to extend beyond six months. The amount not recovered will be added to subsequent recovery periods with a true-up for the extraordinary cost at the end of the Commission approved recovery time period for the extraordinary cost.

While in all likelihood the party asking for an extended recovery period for extraordinary cost would be Empire, this provision would allow for the Commission or any party to ask for an extension of the time over which extraordinary costs would be recovered. While any party can ask for an extended recovery period, the extension must be Commission approved.

Under this tariff sheet provision, the recovery period could be extended. Customers would be responsible for interest at the short-term interest rate prescribed for the FAC by statute and would only pay 95% of the costs above the amount included in the base rates. However, the language does not preclude Empire from requesting in a case before the Commission, different treatment for deferring extraordinary costs in a liability account for potential future recovery.

This language is similar to the tariff language the Commission recently approved for The Empire District Gas Company and Liberty Utilities Midstates Natural Gas in their purchased gas adjustment tariff sheets. I recommended similar language be added to the Ameren Missouri FAC tariff sheet in Ameren Missouri's rate case ER-2021-0240.

Q. Why are you recommending that the Commission order language added to Empire's FAC tariff sheets to explicitly prohibit Empire from recovering retirement and/or decommissioning costs related to the retirement of a generation plant through its FAC?

A. Empire's FAC includes fuel costs associated with generating plants. Retirement and decommissioning costs are not costs incurred to generate electricity therefore these costs should not flow through a FAC.

Q. Why are you making this recommendation now?

A. Empire and Evergy Metro both included in their FACs final "coal inventory adjustments" for basemat coal of generation plants at retirement, only to remove them when opposed. Modifying the FAC to specifically state retirement and decommissioning costs are not FAC costs should prevent this from happening again.

Q. Does this mean that Empire cannot recover retirement and decommissioning costs?

A. No. It can still request recovery of such costs, but not through its FAC.

Q. Why do you recommend Empire's FAC be modified to require removal of fuel and purchased power costs for research and development projects?

A. While I am not aware that Empire has any such research and development project, Ameren Missouri does have such a project, and the issue arose there. For Empire this is preventative language. It is better to have such language and not need it than to need it and not have clear language in the FAC tariff sheets.

Q. What is your recommendation regarding the percentage of SPP transmission costs and revenues that should be included in Empire's FAC?

A. I am recommending that the Commission continue with the methodology it has approved for Empire and the other Missouri electric utilities using the fuel and purchased power costs estimated by Staff and based on the most currently available information.

Q. On what is the current percentage based?

A. In its *Report and Order* in the Empire rate case ER-2014-0351, the Commission found the Empire's transmission costs that should be included in its FAC were:

1) The costs to transmit electric power it did not generate to its own load (true purchased power); and
2) The costs to transmit excess electric power it is selling to third parties to locations outside the SPP (off-system sales).

Empire and the parties in its next general rate case, ER-2016-0023, agreed to continue to use this methodology to determine how much of the non-administrative SPP costs were to be included in its FAC. In the last rate case, ER-2019-0374, Empire asked, as it has in this case, for the all of its SPP transmission costs to be included in its FAC. The Commission found changing to 100% of SPP costs being included in Empire's FAC would be inconsistent with prior Commission rulings and with the transmission percentages included in the other Missouri electric utilities' FACs.

This is still the way the percentage of regional transmission organization ("RTO") transmission costs included in the other utilities FACs are calculated and for the percentage of transmission revenues Ameren Missouri includes in its FAC also.

Q. Why are you proposing transmission revenues be included in Empire's FAC?

A. Empire receives revenues under the same SPP schedules for which it is assessed charges. For consistency, the costs should be offset by the revenues received for that same service.

Q. Does this conclude your direct testimony?

A. Yes.