EXHIBIT

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Witness/Type of Exhibit:	Mantle/Rebuttal
Sponsoring Party:	Public Counsel
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REBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EA-2019-0010

** **

Denotes Confidential Information that has been Redacted

February 5, 2019

OPC Exhibit No. 205-P
Date 4-8-19 Reporter TV
File No. EA-2019-0010

PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Certificates of Convenience and Necessity Related to Wind Generation Facilities	))))	File No. EA-2019-0010

AFFIDAVIT OF LENA MANTLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

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

1. My name is Lena 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 5th day of February 2019.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
JERENE A. BUCKMAN
My Commission Expires
August 23, 2021
Cole County
Commission #13754037

Jerene A. Buckman

Jerene A. Buckman
Notary Public

My Commission expires August 23, 2021.

REBUTTAL TESTIMONY

OF

LENA M. MANTLE, P.E.

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EA-2019-0010

Q. What is your name?

A. My name is Lena M. Mantle.

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

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

Q. What is your business address?

A. My business address is P.O. Box 2230, Jefferson City, Missouri 65102.

Q. What is your experience and what are your qualifications?

A. I worked for the Missouri Public Service Commission Staff ("Staff") from August 1983 until I retired in December 2012. During the time that I was employed at the Missouri Public Service Commission ("Commission"), I progressively worked as an Economist, as an Engineer, as an Engineering Supervisor, and finally as the Manager of the Commission's Energy Department. In August 2014, I started working for the OPC in my current position, as a Senior Analyst.

Attached as Schedule LMM-R-1 is a brief summary of my experience with OPC and Staff, along with a list of the Commission cases in which I filed testimony, Commission rulemakings in which I participated, and Commission reports to which I contributed. I am a Registered Professional Engineer in the State of Missouri.

Q. What is The Empire District Electric Company requesting in this case?

A. The Empire District Electric Company ("Empire") is requesting certificates of convenience and necessity ("CCN") for three aggregations of electricity generating wind turbines—the Kings Point and North Fork Ridge wind farms in Missouri, and the Neosho Ridge wind farm in Kansas. Empire plans that the Kings Point, North Fork Ridge, and Neosho Ridge wind farms will be capable of generating up to 150 MW, 150 MW and 300 MW of electricity, respectively.

Q. What are some of the important aspects of the information that Empire is presenting to support its CCN requests?

A. Empire estimates that it will cost approximately $1.1 billion to build these three wind farms.[1] Empire estimates that if it is able to obtain investment partners (tax equity partners or "TEPs")[2] who can take full advantage of the production tax credits that these wind farms will generate (if they produce electricity soon enough to be eligible), then adding $1.1 billion of generation will cost Empire, and it anticipates its customers, approximately ** ** in capital investment. Even at approximately half the total cost to build them, these wind farms would increase Empire's current rate base of approximately $1.4 billion by ** **

Empire does not need the additional capacity or energy from these farms to provide service to its customers now or for the foreseeable future. Empire currently has more than enough generation to meet its forecast of its customers' capacity and energy requirements through the next decade. Empire is instead planning on this large investment because it speculates that the revenues from the sales of energy to the Southwest Power Pool ("SPP") Integrated Market that these farms generate over the next 30 years will exceed what Empire customers pay for the wind farms in their rates.

[1] Direct testimony of Empire witness Todd Mooney, page 23, lines 10-11.
[2] See Rebuttal testimony of OPC witness John S. Riley, page 4.

Empire's own analysis is that the net present value of the revenue these farms will generate over the first ten years is less than the costs that rate-payers would incur for these projects over those same ten years.[3] In other words, Empire predicts that, for at least a third of the timeline it projects, its customers will be paying more in costs than revenue Empire may supposedly generate. According to Empire's own modeling, its customers have to wait over a decade to see any consistent "savings" from these projects, while Empire enjoys immediate recoupment of its investment. The rate impacts of its increase in rate base and other expenses due to these wind farms will be greater than the SPP market revenues from the sales of the energy these wind farms generate.

While, if Empire's predictions are correct, Empire's customers receive no benefit for at least ten years, Empire's analyses includes Empire receiving both a return of and on these wind farms and the TEPs also receiving an essentially guaranteed return of and on their investments. It is only after Empire's predicted future market prices increase by 65% from current levels does Empire project that the SPP market revenues generated from these wind farms will be significantly greater than the cost of the wind farms. This is also only after the tax equity partner has sold its portion of the wind farms to Empire at a price that will be determined by the revenues the wind farms generates in years six through ten of the TEP agreement that Empire has not yet negotiated.[4]

Q. What is the purpose of your testimony?

A. I raise concerns with the suitability of relying on projected SPP market prices for evaluating the benefits to Empire's customers of Empire building and owning these wind farms as regulated assets. Much of the analysis of the cost/benefit to

[3] "Wind Study 600 MW Wind Plans_F17_High_Low McMahon.xlsx", sheet "DATA-Reference Case" provided as workpapers to the Non-unanimous Stipulation and Agreement filed on April 25, 2018 in Case No. EO-2018-0092.

[4] See Rebuttal testimony of OPC witness John A. Robinett, page 9.

Empire's customers, and the parameters for the agreement with the TEPs upon which Empire relies are dependent on projected market prices. In this testimony I provide information showing that the market prices Empire relies on to estimate the future SPP market revenues these wind projects will create are highly uncertain.

Q. **Do you have any recommendations for the Commission?**

A. Yes. OPC has significant concerns with Empire's proposal because the benefits to the customers are entirely reliant on SPP market prices, prices which Empire forecasts for the next 30 years in this case. Information provided by Empire shows that SPP market prices are nearly impossible to predict two years into the future, let alone 30 years into the future. These wind farms, which Empire does not need to meet its customer load requirements, put incredible economic risks on Empire's customers.

If the Commission grants Empire one or more of the CCNs it requests, then OPC recommends the Commission require Empire to hold its customers harmless by imposing the condition on each CCN that Empire make its customers whole through rates for each year during life of the wind farms when the wind farms do not generate net cash through the Holdcos equal to or greater than the cost to the customers. This includes all costs, but not limited to, the return of and on the capital investment for these wind farms and all operations and maintenance costs and administrative and general costs allocated to the wind farms.

If the Commission grants Empire one or more CCNs in this case, including this condition is imperative to protect customers because the potential risk of the "savings" Empire touts not materializing is so significant, without this condition the harmful impact on customers and Southwest Missouri could be substantial.

Q. How does Empire use SPP market prices to justify these wind farms?

A. Empire uses market prices in several ways. In the previous case in which Empire sought Commission approval for its plan to build wind farms, Case No. EO-2018-0092, Empire used estimated market prices to determine the "savings" its customers were projected to realize over the 30-year life of the wind farms. In its initial filing in Case No. EO-2018-0092, Empire relied on market prices that its consultants, ABB, estimated and which Empire had used in its 2016 triennial resource plan filing with the Commission.[5] Empire filed this IRP resource plan in April 2016, which means that much of the analysis was conducted in 2015 using data from prior to 2016 and likely only a portion of 2015. Since the SPP integrated market did not start until March 2014, there was limited SPP-specific market price data available to estimate future market prices used in the resource planning process and, therefore, in the subsequent estimates Empire is using to support its plan to build the wind farms it brought before the Commission in Case No. EO-2018-0092.

Because Empire used the market price data from its 2016 resource planning process, Empire titled the market forecast it used in its initial analysis in EO-2018-0092 its "2016 Forecast," even though it is unlikely that it includes much, if any, market information from 2016.

Q. Did Empire ever update its 2016 Forecast?

A. Yes. Empire, in its workpapers supporting the April 24, 2018, *Non-Unanimous Stipulation and Agreement* filed in Case No. EO-2018-0092, provided the results of an additional analysis using an updated market price forecast. Empire titled this updated market forecast its "2017 Forecast," not necessarily because it includes information from the year of 2017 but because the forecast was made a year after the 2016 Forecast.

Q. How do the 2017 Forecast and the 2016 Forecast differ?

A. The market prices in the 2017 Forecast are much lower than those in the 2016 Forecast. The graph below plots the annual average market prices of the 2016 and 2017 forecasts by year.

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Beginning in 2020, the year before Empire takes ownership of the wind farms, and continuing through 2036, the 2017 annual average forecasted market price is approximately 20% lower than the 2016 forecasted market price.

Q. How does the updated market price forecast impact the results of Empire's analysis of the benefits of the wind farms to Empire's customers?

A. It reduced Empire's estimate of the benefits. The table below contains the results of this analysis.[6] The columns labeled 2016 and 2017 are the net present value ("NPV") of the difference between revenue requirements of the resource planning base plan[7] and the wind farms as agreed to in the *Non-unanimous Stipulation and*

[5] EO-2018-0092, McMahon Direct, page 11, lines 8 – 10.
[6] "Wind Study 600 MW Wind Plans_F17_High_Low McMahon.xlsx" sheet "DATA-Reference Case," provided as workpapers to the Non-unanimous Stipulation and Agreement filed on April 25, 2018 in Case No. EO-2018-0092.
[7] Preferred plan as defined in the 2016 Resource Plan filing.

Agreement in Case No. EO-2018-0092, using Empire's 2016 market forecast and Empire's updated 2017 market forecast.

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The significance of this is that updating the market forecast with an additional year of information changed the market price forecasts enough such that the wind farms went from being projected to be economically beneficial to Empire's customers in the first ten years, based on the 2016 market forecast, to being projected to be economically adverse to Empire's customers, based on the 2017 forecast. The update also resulted in a 43% reduction in the 20-year benefit and a 34% reduction in the 30-year benefit.

Q. What is does "net present value" mean?

A. Net present value is a common measure of the value of future revenues (positive or negative) taking into account the time value of money. For example, $100 today is worth more than $100 next year because $100 today can earn a return and be equal to more than $100 in next year.

In Empire's analysis, in the first ten years there were some years where the expected revenue was marginally greater than the cost but over the ten years, taking into account the time value of money at ** **, Empire estimated the net present value of these wind farms to be ** **

Q. Empire witness Blake A. Mertens states in his direct testimony in this case, "The [Generation Fleet Savings Analysis] modeling indicated that adding wind generation to Empire's portfolio in or near Empire's service territory was not only possible, but brought significant benefits to our customers."[8] When was the Generation Fleet Savings Analysis modeling to which he refers performed?

A. Sometime before April 25, 2018.

Q. Empire filed this case on October 18, 2018, and the Commission consolidated Case No. EA-2019-0118 with this case on December 19, 2018. Did Empire rerun its analysis of the impact on customers with updated forecast market prices for this case?

A. No, it did not. According to Empire's response to OPC data request 2001 it did not perform an update "since the ultimately executed contracts [levelized cost of energies] for the portfolio of wind projects (Kings Point, North Fork Ridge and Neosho Ridge) were at or below the $23.89 contemplated in that docket."

Q. Can you measure the accuracy of Empire's 2016 and 2017 market price forecasts?

A. While I do not have any statistical measure of accuracy, I was able to create the following graph with information from Empire's market forecasts[9] and the actual market prices[10] at the Elk River generation node[11] that shows the 2016 and 2017 forecasts to be inaccurate:

[8] Page 4, lines 21 – 23.
[9] Market prices provided in response to OPC data request 8034 in Case No. EO-2018-0092.
[10] Market prices provided in response to OPC data request 8508 in Case No. EA-2019-0010.
[11] Empire has a purchased power agreement to receive the energy generated at the Elk River Wind farm located in southeast Kansas through 2028. This generation node was chosen for this analysis because of the proximity of the Elk River Wind farm to the proposed Neosho Ridge Wind Farm.

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This graph shows that both the 2016 and 2017 forecasts[12] of the average market prices for 2017 were too high (22%) and the forecasts for 2018 were too low (14% and 7% for 2016 and 2017, respectively).

Q. What does this graph indicate to you about Empire's 2016 and 2017 Forecasts?

A. All forecasts will have uncertainties in the long-term, but short-term predictions are the hallmark of accurate forecasting. The information shown above indicates that the methodology Empire used to forecast 2017 and 2018 SPP market prices did not accurately estimate the near-term market prices. Since a forecast should be most accurate in the near-term, this raises great concern with using the results of these market price forecasts for the underlying support to make a $500 million investment in generation resources that is not needed to serve captive customers.

Q. Is there any method that could more accurately forecast market prices?

[12] The forecasted market price for 2017 was the same for both the 2016 and 2017 forecasts.

A. I do not know of any. Review of actual SPP market price data and the underlying market points to reasons other than the method used to make the forecasts for the forecasts being so different from what actually occurred in the SPP market in the near-term. These include having a limited amount of data to work with, and an evolving market that makes it impossible for any forecast to be accurate.

Q. What leads you to believe that data constraints are leading to inaccurate forecasts?

A. The SPP market has only been operating since March 2015, so when Empire filed this application there were only 43 months of actual historical data available for this new market. While this may seem like a lot of data, it really is not. The SPP market is an hourly market, and the price in each hour may respond to different variables specific to the hour including the time of the year and time of the day, the load requirements, and the probability of wind availability. This means that there were only three or four data points for each hour on which to determine a relationship that should include at least the time of the day, season of the year, day of the week, natural gas prices, and availability of other generating resources.

In general, a forecast created from a small amount of historical data is questionable. In the case of SPP market prices, an examination of the available data shows that in addition to having a limited amount of data to input into a forecast, the data that is available is erratic, which should result in greater skepticism regarding the accuracy of any market price forecast – short-term or long-term.

The graph below shows the average hourly market prices for the years 2015 through 2017 at one of the Empire SPP generation nodes, the Elk River wind farm,[13] which Empire provided to OPC in its response to OPC data request 8508.

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With just these three data points, it looks as if the annual market price is easy to forecast, and the trend is definitely downward.

Q. If you used only these three data points to forecast the SPP average market price for 2018, how good would that forecast be?

A. The forecasted price would be far below the actual price. The following graph shows the actual average SPP market prices for 2015 through 2018.

[13] Empire has a purchased power agreement with Elk River Wind farm for capacity and energy through 2025.

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Q. As an analyst, what does this graph tell you?

A. First of all, although every forecast is limited in explanatory power, my review of the available historical data, and Empire's 2016 and 2017 forecasts, confirms my statistical experience that forecasts based on very little historical data are highly likely to be very wrong.

Secondly, market prices are driven by a number of factors, and should not be forecasted merely based on price trends over time.

Q. Did you look into what factors may have driven the increase in actual market prices in 2018 for whether they should be considered when forecasting SPP market prices?

A. Yes. I reviewed the winter, spring, summer, and fall *2018 State of the Market* reports published by the SPP Market Monitoring Unit. One of the historical predictors of market prices in energy markets has been the price of natural gas because, typically, the marginal generating unit upon which the market price is set is a natural gas unit. However according to all four of these reports, SPP market prices did not follow this expected correlation during 2018, as the following table shows:

		Change From 2017 Natural Gas Prices	Change from 2017 SPP Day-Ahead Price
Winter	Dec 2017 – Feb 2018	-14%	Same
Spring	Mar 2018 – May 2018	-20%	+13%
Summer	Jun 2018 – Aug 2018	-8%	-2%
Fall	Sep 2018 – Nov 2018	+11	+38%

Q. Did the SPP Market Monitoring Unit explain why energy market prices did not follow natural gas prices?

A. Yes. For Winter of 2018, the SPP Market Monitoring Unit opined that the market prices over the three-month time period December 2017 through February 2018 stayed the same due to higher December gas prices in 2017 than 2016, and higher loads across all three months in the Winter 2018.

The SPP Market Monitoring Unit partially attributed the disparity between the change in natural gas prices and market prices in the Spring of 2018 to higher loads, as well as fewer hours with negative prices and generation outages.

While the SPP Market Monitoring Unit did not opine why the market prices did not decline as much as the natural gas prices between the summers of 2017 and 2018, it did state that the SPP load for the Summer of 2018 was up nearly 5% from the SPP load in the Summer of 2017.

Finally, the SPP Market Monitoring Unit attributed the large increase in market prices in Fall 2018 to higher gas prices, higher loads, less wind generation and fewer negative prices.

Q. What do you think of the SPP Market Monitoring Unit's opinions for why energy market prices did not follow natural gas prices in 2018?

A. Their opinions are reliable. They are experts on the SPP energy market and they follow what is happening in the SPP and how that affects market prices on a daily basis.

Q. You mentioned that the SPP Market Monitoring Unit cited to less wind generation in 2018. Does that mean that there were fewer wind turbines operating in 2018 than in 2017?

A. No. The report states that wind capacity increased from 15.2 gigawatts ("GW") in the Fall of 2017 to just under 20 GW in the Fall of 2018. What the statement by the Market Monitoring Unit is referring to is that despite an increase in the available wind-powered electricity generating resources, wind turbines generated less electricity in 2018 than 2017.

Q. Why would this occur?

A. There are two reasons why the generation would be less. The first, which is very unlikely, is that a significant number of wind turbines were unavailable due to forced or planned outages.

The second, more probable reason, is that the Fall of 2018 was less windy than the fall of 2017. The amount of energy that a wind turbine can generate is weather dependent. Wind is an intermittent resource. While an operator can turn off a wind turbine so that it does not generate energy when the wind blows, a wind turbine cannot generate energy when the wind is not blowing. While less wind may result in higher SPP market prices, less wind may also result in less wind farm revenues, since wind farms only create revenues when they are generating energy.

Q. Should an analyst consider all the things mentioned by the Market Monitoring Unit as impacting market prices when forecasting SPP market prices?

A. Yes. Actual market prices should be normalized to account for the impact of weather on loads and changes in wind strength prior to being used to forecast future market prices. The impact of different natural gas price forecasts should also be considered. In addition, an analyst should take into consideration the amount and type of generation that is likely to be added to and retired from the participation in the SPP energy market.

Q. Is the method Empire used to generate its market price forecasts a good forecasting method?

A. Based on the information that Empire has provided, it is not. The SPP energy market is still relatively new, and any new market is hard to predict. Wind generation is being added to the SPP markets, not because it is required by customers or because of market prices, but because of tax incentives. Utilities across the SPP are choosing to prematurely retire fossil-fuel generation plants. All these factors make accurately forecasting SPP market prices extremely difficult.

Q. Is there anything else that an analyst should consider when forecasting SPP market prices?

A. Yes. The projected end to the production tax credits is resulting in ever-increasing amounts of wind generated electricity resources being added in the SPP footprint and markets. Wind is an intermittent generation resource. The SPP cannot control when wind turbines provide electrical energy, except to curtail them. Because of the production tax credits, it is economic for the owners of wind turbines to generate energy, even when there is a negative price for electricity. This is different from in the past when system operators could call upon a plant to generate electricity and know both (1) when it could provide that energy and (2) quantify how much energy it could provide. The SPP day-ahead and real-time markets are relatively new markets. The SPP is changing its rules and its requirements frequently to make its markets more efficient, and to take into account the new realities associated with intermittent resources. These changes to market rules affect market prices, and how market prices should be forecasted.

Q. OPC did not raise concerns with Empire's market forecasts in the context of Empire's 2016 resource planning process. Why is it so concerned with them now?

A. The purpose of the Commission's resource planning process is to require utilities to look at the best information available for *meeting the load requirements of their customers*. A comprehensive planning process includes looking at the best estimate of future market prices. Much of the benefit of the planning process is that it requires utilities to consider various inputs, and come up with a robust portfolio of generating assets for flexibility in reacting to various potential futures.

Here, Empire is not asking to build these wind farms to meet the load requirements of its customers. Instead, Empire is justifying these wind farms on the rationale that they could provide a revenue stream that when viewed over the next 30 years may reduce its customers' electric utility bills aggregated over those next 30 years from what they otherwise would be. However, the foundation of this revenue stream is a market price forecast for new, evolving SPP markets.

Further, even based on Empire's projections, its customers will not see their bills reduced because of Empire's investment in these wind farms for 11 to 30 years into the future.

Q. What is an Independent Power Producer?

A. An independent power producer ("IPP") owns facilities that generate electric power for sale to electric utilities. An IPP owns a portion of the Dogwood Energy

Facility near Pleasant Hill, Missouri and it sells its portion of the electricity generated by the facility to other utilities either directly or through an energy market.

Q. Do affiliates of Empire own wind farms that Independent Power Producers operate?

A. Yes. Algonquin Power Company, an affiliate of Empire that reports to the same holding company, Algonquin Power & Utilities Corporation, owns 1,400 MW of generation in the United States and Canada of which 905 MW is wind generation.

Q. In your opinion, from a shareholder's perspective, is it better to own a wind farm and operate it as an IPP or for it to be included in a rate-regulated utility's rate base?

A. It depends. If a shareholder is confident the wind farm will generate more revenues than it costs to build, own, maintain and operate, and more revenues than it would generate through customer rates, then shareholders should prefer to own and operate the wind farm as an IPP where they receive all of the net revenues. However, if shareholders want more profit certainty on their investment, then they may prefer for the wind farm to be included in a regulated utility's revenue requirement where they essentially are assured of a return of their investment plus a healthy profit.

Q. Could these wind farms that Empire is proposing to build be built as IPP projects?

A. Yes.

Q. Are there other ways that SPP market prices impact the analysis of the economic value of these wind farms to Empire's customers?

A. Yes, there are. In his direct testimony, Mr. Mooney states, "In order to finance renewable projects, banks insist on these agreements to be in place to provide a certain price for the commodity." The agreement that Mr. Mooney is referring to is an agreement for Empire to pay the Holdcos an amount for each megawatt-hour ("MWh") the wind farms generate. Empire refers to this amount as a "hedge." It is actually just a payment arrangement with the Holdco where Empire will make sure that the Holdco receives a certain amount of revenues, instead of relying on uncertain SPP market revenues.

The yet to-be-determined amount per MWh that Empire will pay for each MWh generated will be set based on forecasted SPP market prices. OPC witness John Riley provides a discussion of this payment in his testimony.

The market price also determines the amount of net cash the Wind Holdcos pay to the TEP in years six through ten, and how much Empire will pay for ownership of the project in year 11.

Q. Are the forecasted market prices Empire plans to use to set the hedges and the buy-out amounts that Empire included in its analysis the same forecasted market prices that Empire used in its customer savings analysis?

A. I cannot tell from Empire's workpapers or data request responses.

Q. With respect to the MWh payment, what happens if the market price forecasts used to set the payment amount is higher than the actual market prices?

A. Assuming the TEP agreement includes the terms as set out in Empire witness Todd Mooney's direct testimony,[14] during the first five years following after the wind farms are built, Empire's customers would be unaffected by market prices being lower than the forecasted market prices. During the first ten years after

[14] Page 20, Table titled "Illustration of Transactions."

building the wind farms, through Empire, Empire's customers pay the MWh payment amount to the Wind Holdcos. Each Wind Holdcos then combines these payments it receives with the SPP revenue it receives and nets the result with its operating costs. According to Mr. Mooney, during the first five years Empire will return all of these net revenues to its customers.

In the table in his testimony,[15] Mr. Mooney provides that in post-construction years six through ten, Empire's customers would still pay the MWh payment for every MWh generated, but the wind farm TEP would receive 25% to 40% of the Holdco's net revenues. This means that the TEP would receive a percentage of the revenues generated from SPP and the MWh payments cost that Empire's customers pay.

In addition, it is my understanding that what Empire pays to a TEP in year 11 to buyout the TEP's ownership of a wind farm is based on the amount of the TEP's then-unrecovered investment and profit. If the market prices are consistently below the MWh payment amount, then it will cost more to buyout the TEP.

Q. Is there any protection that the Commission could afford Empire's customers in this case that would reduce the future market prices risk to which Empire is proposing to expose them?

A. Yes. I recommend the Commission impose the condition on each CCN that Empire make its customers whole through rates for each year during life of the wind farms when the wind farms do not generate net cash through the Holdcos equal to or greater than the cost to the customers. This includes all costs including, but not limited to, the return of and on the capital investment for these wind farms and all operations and maintenance costs and administrative and general costs allocated to the wind farms. If the Commission grants Empire one or more CCNs in this case, including this condition is imperative to protect customers because the potential risk of the "savings" Empire touts not materializing is so significant, without this condition the harmful impact on customers and Southwest Missouri could be substantial.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

[15] Id.

Education and Work Experience Background of

Lena M. Mantle, P.E.

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

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

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

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

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

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

Office of Public Counsel Case Listing

Case	Filing Type	Issue
GO-2019-0058 & GO-2019-0059	Direct, Rebuttal	Weather
ER-2018-0145 & ER-2018-0146	Direct, Rebuttal, Surrebuttal	Purchased Power, Customer Bills, Crossroads, Resource Planning
EO-2018-0092	Rebuttal, Surrebuttal	OPC Opposition of Request for Approval of Changes to Resource Plan
GR-2017-0215 & GR-2017-0216	Direct, Rebuttal, Surrebuttal	Energy Efficiency and Low-Income Programs
EO-2017-0065	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause Prudence Review
ER-2016-0285	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2016-0156	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause, Resource Planning
ER-2016-0023	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
WR-2015-0301	Direct, Rebuttal, Surrebuttal	Revenues, Environmental Cost Recovery Mechanism
ER-2014-0370	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0351	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0258	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
EC-2014-0224	Surrebuttal	Policy, Rate Design

Missouri Public Service Commission Rules

4 CSR 240-3.130	Filing Requirements and Schedule of Fees for Applications for Approval of Electric Service Territorial Agreements and Petitions for Designation of Electric Service Areas
4 CSR 240-3.135	Filing Requirements and Schedule of Fees Applicable to Applications for Post-Annexation Assignment of Exclusive Service Territories and Determination of Compensation
4 CSR 240-3.161	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.162	Electric Utility Environmental Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.190	Reporting Requirements for Electric Utilities and Rural Electric Cooperatives
4 CSR 240-14	Utility Promotional Practices
4 CSR 240-18	Safety Standards
4 CSR 240-20.015	Affiliate Transactions
4 CSR 240-20.017	HVAC Services Affiliate Transactions
4 CSR 240-20.090	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms
4 CSR 240-20.091	Electric Utility Environmental Cost Recovery Mechanisms
4 CSR 240-22	Electric Utility Resource Planning
4 CSR 240-80.015	Affiliate Transactions
4 CSR 240-80.017	HVAC Services Affiliate Transactions

Staff Direct Testimony Reports

ER-2012-0175	Capacity Allocation, Capacity Planning
ER-2012-0166	Fuel Adjustment Clause
ER-2011-0028	Fuel Adjustment Clause
ER-2010-0356	Resource Planning Issues
ER-2010-0036	Environmental Cost Recovery Mechanism
HR-2009-0092	Fuel Adjustment Rider
ER-2009-0090	Fuel Adjustment Clause, Capacity Requirements
ER-2008-0318	Fuel Adjustment Clause
ER-2008-0093	Fuel Adjustment Clause, Experimental Low-Income Program
ER-2007-0291	DSM Cost Recovery

Missouri Public Service Commission Staff Testimony

Case No.	Filing Type	Issue
ER-2012-0175	Rebuttal, Surrebuttal	Resource Planning Capacity Allocation
ER-2012-0166	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EO-2012-0074	Direct/Rebuttal	Fuel Adjustment Clause Prudence
EO-2011-0390	Rebuttal	Resource Planning Fuel Adjustment Clause
ER-2011-0028	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EU-2012-0027	Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2010-0356	Rebuttal, Surrebuttal	Resource Planning Allocation of Iatan 2
EO-2010-0255	Direct/Rebuttal	
ER-2010-0036	Supplemental Direct, Surrebuttal	Fuel Adjustment Clause
ER-2009-0090	Surrebuttal	Capacity Requirements
ER-2008-0318	Surrebuttal	Fuel Adjustment Clause
ER-2008-0093	Rebuttal, Surrebuttal	Fuel Adjustment Clause Low-Income Program
ER-2007-0004	Direct, Surrebuttal	Resource Planning
GR-2007-0003	Direct	Energy Efficiency Program Cost Recovery
ER-2007-0002	Direct	Demand-Side Program Cost Recovery
ER-2006-0315	Supplemental Direct, Rebuttal	Energy Forecast Demand-Side Programs Low-Income Programs
ER-2006-0314	Rebuttal	Jurisdictional Allocation Factor
EA-2006-0309	Rebuttal, Surrebuttal	Resource Planning
ER-2005-0436	Direct, Rebuttal, Surrebuttal	Low-Income Programs Energy Efficiency Programs Resource Planning
EO-2005-0329	Spontaneous	Demand-Side Programs Resource Planning

Missouri Public Service Commission Staff Case Listing (cont.)

EO-2005-0293	Spontaneous	Demand-Side Programs Resource Planning
ER-2004-0570	Direct, Rebuttal, Surrebuttal	Reliability Indices Energy Efficiency Programs Wind Research Program
EF-2003-0465	Rebuttal	Resource Planning
ER-2002-424	Direct	Derivation of Normal Weather
EC-2002-1	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-672	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-299	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EM-2000-369	Direct	Load Research
EM-2000-292	Direct	Load Research
EM-97-515	Direct	Normalization of Net System
ER-97-394, et. al.	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System Energy Audit Tariff
EO-94-174	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
ER-97-81	Direct	Weather Normalization of Class Sales Weather Normalization of Net System TES Tariff
ER-95-279	Direct	Normalization of Net System
ET-95-209	Rebuttal, Surrebuttal	New Construction Pilot Program
EO-94-199	Direct	Normalization of Net System
ER-94-163	Direct	Normalization of Net System
ER-93-37	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-91-74, et. al.	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-90-251	Rebuttal	Promotional Practices Variance
ER-90-138	Direct	Weather Normalization of Net System
ER-90-101	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-85-128, et. al.	Direct	Demand-Side Update
ER-84-105	Direct	Demand-Side Update