EXHIBIT

Exhibit No.:	
Issue(s)	Response to Intervenors' Rebuttal Testimony
Witness/Type of Exhibit:	Marke/Surrebuttal
Sponsoring Party:	Public Counsel
Case No.:	EA-2019-0010

SURREBUTTAL TESTIMONY

OF

GEOFF MARKE

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EA-2019-0010

** **

Denotes Highly Confidential Information that has been Redacted

March 5, 2019

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 GEOFF MARKE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Geoff Marke, of lawful age and being first duly sworn, deposes and states:

1. My name is Geoff Marke. I am a Regulatory Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal 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.

Geoff Marke
Chief Economist

Subscribed and sworn to me this 5th day of March 2019.

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

Jerene A. Buckman
Notary Public

My Commission expires August 23, 2021.

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SURREBUTTAL TESTIMONY

OF

GEOFF MARKE

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EA-2019-0010

I. INTRODUCTION

Q. Please state your name, title and business address.

A. Geoffrey Marke, PhD, Chief Economist, Office of the Public Counsel ("OPC"), P.O. Box 2230, Jefferson City, Missouri 65102.

Q. Are you the same Geoff Marke who filed rebuttal testimony in Case No. EA-2019-0010?

A. I am.

Q. What is the purpose of your rebuttal testimony?

A. I primarily respond to Staff who, despite voicing real concerns regarding the Empire District Electric Company's ("Empire" or the "Company") proposed wind energy projects, ultimately aligns with Empire's desired ratepayer backed investment. The Company is clearly confident in the long-term proposition of investing $1.1 billion dollars in the hopes of making excess money in off-system sales for decades from intermittent wind, located in an area with a poor wind profile, in a rapidly changing ("vertically integrated") southwest Power Pool ("SPP") market, all the while competing in a field that is making incredible advancements in generation and storage. Empire is so confident, that they stopped modeling risks altogether since early 2018 for an investment that will not be operational until 2021. They are confident that their 2017 natural gas prices, four years of historic SPP market data and high wind forecast of 6.5 GW of competing wind will be accurate enough to forecast the next thirty to forty years of operation. They are also confident in moving forward without any SPP Generation Interconnection Agreements or without any terms or commitments from any tax equity partner(s). This confidence has seemingly convinced Staff and other parties, but not myself. Empire's applications make the utility the cost causer and the ratepayer the cost bearer, and represent a significant departure from traditional cost of service regulation and a slippery slope for future regulatory policy.

My misgivings notwithstanding, I recommend that if the Commission elects to move forward with any CCN approval, that those approvals be married to hold harmless conditions for ratepayers. Ratepayers should not be forced to function as market investors of $1.1 billion that is not necessary for its cost of service—especially, when no additional supply side investment is needed until at least 2029 and most likely longer now with the loss of 77 megawatt ("MW") of municipal customer load this past year.

Empire should be required to make its captive ratepayers whole through rates for each year during the life of the wind farms. In other words, when the wind farms do not generate net cash through the Holdcos equal to or greater than the costs of the wind farm included in rates, customers would be held harmless. This condition includes all costs, including, but not limited to the return of an on the capital investment for the merchant generation, all operations and maintenance costs, and administrative and general costs allocated to the wind farms when the Commission determines Empire's cost of service for setting rates.

II. RESPONSE TO THE MISSOURI PUBLIC SERVICE COMMISSION STAFF

Q. What concerns with Empire's applications does Staff raise in its rebuttal report?

A. Generally, Staff's areas of concern are as follows:

- Empire's Levelized Cost of Energy "(LCOE") inputs
- Future SPP wind additions
- Future market prices in the SPP Integrated Market
- Wind Farm Net Capacity Factor uncertainty
- Empire Missouri retail rate impact in the first ten years
- Lack of permits, studies and interconnection agreements

I respond to each of these concerns in turn.

Q. What is Staff's concern regarding Empire's LCOE inputs?

A. According to Staff witness Ms. Eubanks:

> [T]he portfolio LCOE of **
>
> ** Therefore, after reviewing Empire's filings and evidence, Staff recommends the Commission not rely on certain evidence Empire put forth to suggest that meeting a specific LCOE threshold constitutes need, in its findings of fact regarding need.[1]

Q. What is your response?

A. I find it very troubling that the primary input in Empire's direct testimony in support of this application, the projects overall LCOE, is specifically called out by Staff as unreliable and that Staff advises the Commission to not rely on Empire's LCOE in its findings of fact regarding need.

[1] EA-2019-0010 Staff Rebuttal Report. p. 21, 2-8.

If the Staff is directing the Commission to distrust this number because Empire calculated it incorrectly then this raises a significant question of what exactly the Commission is to rely upon for granting the CCNs. If the sole reason for granting the CCNs would be to promote renewable wind energy, to realize the benefits of a tax equity partner, and the urgency of expiring tax credits, then the Commission should also take into consideration that wind is coming online in SPP regardless of these wind farm projects (and Empire's customers are benefiting from that already). Empire has no tax equity partners to date, and it appears the prospects of Production Tax Credits ("PTCs") being renewed seem good.

Q. Why do you believe the PTCs have a good chance of being renewed?

A. For one, the U.S. Congress has renewed them previously. Second, there are politically practical reasons to believe this window will not be closed forever. As *Forbes*' Michael Lynch states:

> But it seems quite obvious that extending Production Tax Credit past its 2020 expiration date will be easy with the current Congress, since Democrats are likely to vote almost unanimously in favor and in the Senate, there should be good Republican support. Unlike the defense industry, this political calculus seems more serendipitous than intentional, especially given the strong Republican presence in states like Texas and North Dakota that have superior potential.[2]

Stated differently, it is hard to kill a subsidy; especially one that is widely popular and benefits both sides of the political spectrum for different reasons.

Q. What is Staff's concern regarding future market prices in the SPP Integrated Market?

A. Staff witness Oligschlaeger states:

> The projected benefits identified by Empire as accruing to its customers as a result of these wind additions is heavily dependent upon assumptions regarding the future amount of wind power that Empire can sell into the SPP Integrated Marketplace and the future price of that power in the SPP IM. Whether Empire's

[2] Lynch, M. (2019) Is renewables' production tax credit bullet proof? *Forbes*. https://www.forbes.com/sites/michaellynch/2019/02/13/is-renewables-production-tax-credit-bullet-proof/#4cdfb2726f3c

projections on these values will prove to be accurate is obviously uncertain, and the amount of projected net customer benefits may be reduced or (in a worst case scenario) eliminated in entirety if Empire's estimates are over-optimistic.[3]

Q. What is your response?

A. I agree with Staff even though Staff omits the many reasonable issues that could impact the assumptions regarding the future amount of wind power that Empire could sell into the SPP IM.

Q. Would you provide some examples?

A. Yes. I will provide five examples, in no particular order of preference:

1. FERC Order 841

On February 15, 2018, FERC issued its final order on Energy Storage Participation enabling storage resource participation in wholesale markets. Though energy storage technologies have been in use for nearly a century, the viability of battery storage as a tool to deliver grid resilience is increasing due to steep and ongoing decline in the price of the technology. FERC recognizes that energy storage viability has outpaced market regulations, and therefore it designed Order 841 to foster head-to-head competition between storage and traditional energy resources.

Although it is still a work in progress, viable, cost-effective storage will now compete with merchant generation wind (and all other resources) in the RTO markets. How much storage will come online and what its exact impact will be on future market prices is unknown; however, it seems reasonable to assume that storage would likely minimize wholesale price fluctuations, and, thus, impact the savings assumptions tied to Empire's merchant generation investment. Importantly, Empire's modeling did not consider energy storage, in part, because no data exists. For its part, the Commission should view storage with a long-term perspective in weighing the reasonableness of this merchant generation venture.

[3] EA-2019-0010 Staff Rebuttal Report p. 28, 17-22

2. Natural Gas Prices:

Empire's estimated customer benefits are largely dependent on its natural gas price assumptions over the next thirty years. This is because Empire is banking on gas prices to increase as supply declines, while relying ever more on wind generation. With that in mind, the Commission should be cognizant that on February 28, 2019, ExxonMobil announced that it had made the world's third biggest natural gas discovery in two years off the coast of Cyprus in the Eastern Mediterranean.

> Based on preliminary interpretation of the well data, the discovery could represent a natural gas resource of approximately 5 trillion to 8 trillion cubic feet (142 billion to 227 billion cubic meters).[4]

Moreover, according to *MarketWatch*:

> The global shale gas market production is expected to grow from 5,563 billion cubic feet in 2016 to 8,000 billion cubic feet in 2024 at CAGR of 4.7% for the same period. . . .
>
> United State is the largest market for this natural gas followed by Canada and China. Eventually, North America is the leading region for shale gas market and will continue to grow over the forecast period. This region was the only active producer of shale gas till 2010. Europe and Middle East & Africa are the second fastest growing market, followed by Asia Pacific and Latin America region.[5]

3. Diminishing Returns from Renewable Generation

I spoke at some length on this issue in my rebuttal testimony by maintaining that the expected inundation of wind assets coming online in the SPP IM will impact future expected earnings,

[4] Koukakis, N. (2019) ExxonMobil makes biggest natural gas discovery in two years off the coast of Cyprus. *CNBC*. https://www.cnbc.com/2019/02/28/exxonmobil-makes-big-natural-gas-discovery-off-the-coast-of-cyprus.html

[5] MarketWatch. (2019) Shale gas market is supposed to reach 8,000 billion cubic feet in 2024. https://www.marketwatch.com/press-release/shale-gas-market-is-supposed-to-reach-8000-billion-cubic-feet-in-2024-2019-03-03

and recent research suggests this issue is at play across all markets. For example Blazquez, et al states:

> Renewables with negligible marginal costs of dispatch—such as solar or wind—could fall victim to their own success after capturing large shares in liberalized power markets. . . . Given existing liberalized market structures in most of the developed economies, future deployment of renewables could become more costly and less scalable because of their impact on electricity prices. . . . Paradoxically, a too successful renewables policy could reduce the efficiency and effectiveness of future such polices.[6]

This phenomenon is also discussed at length in the surrebuttal testimony of OPC witness Lena Mantle including attachments from similar conclusions from researchers at Lawrence Berkeley National Labs and the Massachusetts Institute of Technology.

4. Wind Variability

There can be considerable variation in wind speeds and output year-to-year. Recent research suggests that the wind energy industry likely overstates the expected annual energy production of proposed wind farms. According to Pryor, et al (2018):

> Inter-annual variability (IAV) of expected annual energy production (AEP) from proposed wind farms plays a key role in dictating project financing. IAV in pre-construction projected AEP and the difference in 50th and 90th percentile (P50 and P90) AEP derives in part from variability in wind climates. <u>However, the magnitude of IAV in wind speeds at/close to wind turbine hub-heights is poorly constrained and maybe overestimated by the 6% standard deviation of annual mean wind speeds that is widely applied within the wind energy industry.</u> Thus there is a need for improved understanding of the long-term wind resource and the inter-annual variability therein in order to generate more robust predictions of the financial value of a wind energy project. . . . <u>These results</u>

[6] Blazquez, et al. (2018) The renewable energy policy paradox. *Renewable and Sustainable Energy Reviews.* 82 (1) 1-5. https://www.sciencedirect.com/science/article/pii/S1364032117312546

indicate it may be appropriate to reduce the IAV applied to pre-construction AEP estimates to account for variability in wind climates, which would decrease the cost of capital for wind farm developments.[7] (emphasis added)

5. Vertically Integrated Characteristics of SPP

The Commission should note that even if the premise of entering the wholesale market with a merchant generation asset was a sound investment in a vacuum, of the litany of RTO markets to invest in, SPP would arguably be the worst option. This is because SPP is both an energy-only market, does not contain member states that have aggressive renewable standards, and is largely populated by vertically integrated utilities who all have a clear financial incentive to build out supply-side generation because they earn a return of and on it. Stated differently, if I were going to invest in a merchant generator, I would look to the deregulated markets (PJM, New England, etc…), not SPP.

Each of these five variables will impact future price assumptions hoped to be gained decades from now.

Q. What is Staff's concern regarding the wind farms' net capacity factors?

A. Staff witness Eubanks states:

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[7] Pryor, et al (2018) Interannual variability of wind climates and wind turbine annual energy production. *Journal of Wind Energy Science* https://www.researchgate.net/publication/326195791_Inter-annual_variability_of_wind_climates_and_wind_turbine_annual_energy_production

[8] Ibid. p. 18, 2-8

**

Q. What is your response?

A. I agree and already articulated this specific concern above. Note that a P50 estimate means that there is 50% likelihood that the actual output will be greater and a 50% likelihood that the actual output will be less. Restated, the magnitude of risk inherent in these applications is dependent, in large part, on the expected net capacity factors attainable from the wind farms, which share the same probability inherent in flipping a coin.

Q. What is Staff's concern regarding the potential rate impacts due to these wind farms over the next ten years?

A. Staff witness Oligschlaeger states:

> A related project risk is that Empire's own modeling of the financial impact of the wind additions shows that in the first ten years of the windfarms' operation minimal net customer savings are expected. This is because of the need to fully pay off the tax equity partner's investment in that ten-year period through receipt of tax benefits and cash distributions, leaving little opportunity for customers to gain material benefits from the Wind Projects over this period. If Empire's assumptions regarding the quantity of and the price of wind power generated by these projects prove to be overly optimistic, ratepayers may be asked to bear significant financial losses for at least the first ten years of wind farm operation.[9]

Q. What is your response?

A. I agree with Staff and Empire that the first ten years will not be financially beneficial for Empire's ratepayers. Where we disagree centers on how much ratepayers will be impacted. However, to my knowledge, no one is suggesting that Empire's rates are going to be reduced

[9] Ibid. p. 28, 23-30.

over the next decade because of this billion dollar merchant investment. I believe there is nothing to suggest that years eleven onward will be any better. The only thing unique about year ten is that the tax equity partner(s) is expected to have recouped its investment plus made its profit. Of course, ratepayers will then experience another large increase to Empire's rate base (albeit at a depreciated an amount) and the savings assumed in the second and third decades of these projects are still predicated on there being an attractive market for off-system sales. That is a far from certain outcome.

Q. Do you have a sense of what the near term rate impact will be?

A. Not definitively. If I could confidently state that rates will increase X% over the next ten years this case would be easier to comprehend, and I likely could a draw definitive conclusion. The problem is that there are many variables, not only in this case, but in any rate case that can impact rates. That being said, I confidently believe the probability that rate increases will be greater than 2.85% a year for the next five years is nearly certain.

Q. Why?

A. Because Empire has not elected to choose Plant-in-Service Accounting ("PISA") as a result of the passage of SB 564.[10] The PISA option caps rates at 2.85%. I struggle with why an electric utility would not elect PISA unless it was confident it would request larger rate increases in the near future.

It is important not to forget that in its last triennial IRP (2016) Empire concluded it did not have to add any additional supply-side investment until 2029. Empire's ratepayers paid for that long reprieve in their electric rates, literally through a compounded rate increases of 62.23% from 2007 to 2016. Since 2016, the only thing that has materially changed about Empire's load is that it has gone down.

Q. What is Staff's concern regarding securing permits?

A. Staff witness Cunigan states:

[10] See also response to OPC DR-2045.

> Empire stated in response to Staff Data Request 0029 that no permits had been obtained at this time and provided the following information showing permits that are anticipated to be needed.[11]

That list contained 44 separate permits and omitted Kansas-specific permits, as it was a November response to Staff's data request. Presumably, there are many Kansas-specific permits as well.

Mr. Cunigan then makes the following recommendation:

> Regarding the application requirements, Staff recommends the Commission include the following two conditions with approval of the CCN:
>
> - Filing of the construction-level plans and specifications prior to commencing construction of each project,
> - Filing of the evidence of all required permits and approvals of affected governmental bodies outlined in Empire's response to Staff Data Request 0029.[12]

Q. What is your response?

A. I agree with Staff, but I would also extend those filing requirements to include applicable Kansas permits if the Commission ultimately approves a CCN for the Neosho Ridge Wind Farm.

Q. What is Staff's concern regarding interconnection agreements?

A. According to Staff witness Shawn Lange:

> **
>
> **[13]

[11] Ibid. p. 6, 23-25
[12] Ibid. p. 10, 4-7
[13] Ibid. p. 29, 20-23

Mr. Lange then lists a series of known ** ** Finally, Mr. Lange notes:

> ** ** All of these concerns would be alleviated if properly taken into account in the updated MPP as proposed by Staff.[14]

Q. What is your response?

A. I inquired into this issue as well. OPC DR-2063 and the subsequent response is as follows.

> Question: Please update the status of each of Empire's Generator Interconnection Agreements ("GIAs") for the three wind farms—Kings Point, North Fork Ridge, and Neosho Ridge (regardless of whether it is Empire or Apex's responsibility). If no updates are available, please provide a narrative explanation and/or expected dates as to when updates will be available.

[14] Ibid. p.34, 5-17 (emphasis added).

> Response: The first round of modeling has not been completed by SPP. Based on a schedule available from SPP, that modeling is expected to be completed on October 20, 2019.

Empire informed me that it would be seeking an interim report in the absence of full approval. I inquired into timeliness of that report as well. OPC DR-2062 and Empire's response follow:

> Question: Please update the status of each of Empire's Interim Generator Interconnection Agreements (Interim "GIAs") for the three wind farms—Kings Point, North Fork Ridge, and Neosho Ridge (regardless of whether it is Empire or Apex's responsibility). If no updates are available, please provide a narrative explanation and/or expected dates as to when updates will be available.
>
> Response: The interim availability studies requested for the three projects have not yet commenced due to SPP resource constraints. SPP has not been able to provide a definitive completion date for these studies.

The absence of any signed SPP interconnection agreement obviously concerns me, let alone the fact that Empire "hopes" to have an answer by October 20, 2019. Being now more than two years after Empire brought its wind farm plans in front of the Commission further compounds my concern.

The Commission should note, as stated in my rebuttal testimony, as of January 2019, SPP has already publically stated that it has approximately 10 GWs of unbuilt wind with signed interconnection agreements and that is more than 3.5 GWs of what was modeled in Empire's "high wind" forecast. It also has over 70 GWs of pending generation interconnection requests—which presumably includes Empire's planned wind farms.[15]

Clearly, SPP is dealing with a flood of applications, and that is delaying the process for Empire. Empire could have mitigated such a scenario had it sought CCN approval to begin with, instead

[15] See EA-2019-0010 Rebuttal Testimony of Geoff Marke p. 14, 4-8.

of first seeking "preapproval" or "directional guidance" from the Commission in 2017 (Case No. EO-2018-0092).

Q. What is your response to Mr. Lange's **

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A. First, I am not entirely sure why Staff considers this to be confidential material. Putting aside that question for a moment, this is a big concern. **

** I disagree with Mr. Lange that an ill-defined 50/50 sharing mechanism for only the first third of the useful life of this wind farm project alleviates this concern. That would merely mitigate "some" of the costs ratepayers would bear for a finite amount of time.

Q. What is curtailment in the context of the proposed projects?

A. In the power sector, "curtailment" means a forced reduction in the energy output from a power producing plant, resulting in the plant's dispatching to the electric grid less than the maximum amount of energy it is capable of generating. Effectively, the grid operator "turns off" or "reduces" the power being fed to it from the transmission lines leading from the power plant to the electric grid, so that less than all of the energy the plant is capable of generating makes its way into the electric grid.

According to the Columbia Environmental Law Review:

> Past experience shows that curtailment is not region-specific and impacts wind farms, irrespective of turbine size, in various locations throughout the country. Curtailment is a very real threat that looms menacingly for operational wind farms whose energy supply flows into a congested electric transmission grid.[16]

Q. Why is curtailment important?

A. PTCs are created only when wind turbines generate electricity and are not curtailed.

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[16] Diamond, K. (2016) Technology, curtailment and transmission: Innovation and challenges facing today's U.S. wind energy. *Columbia Journal of Environmental Law*—Field Report. http://www.columbiaenvironmentallaw.org/wp-content/uploads/sites/14/2016/04/Diamond_-_Innovations_and_Challenges_Facing_US_Wind_Energy__FR_-1.pdf

Q. Did Staff propose any additional conditions related to curtailment?

A. Yes. Staff proposed that Empire be required to complete a sensitivity analysis on curtailment and the dispatching down of each Wind Project.[17]

Q. Do you support this?

A. Yes. But these exercises should have already have been undertaken. Understand that a curtailment and dispatch down of each Wind Project will only result in a reduction in the Net Capacity Factor of these wind projects and therefore a reduction in overall savings. The only reason I can see to not undertake this obvious exercise is if you do not want to know the results.

Putting that issue aside, I am not sure what the results will do to inform this Commission now. If the results come back in six months and present a 50% probability of a 3% reduction over the life of these assets, will Staff hold the MPP constant for what was assumed in the original model? Can the model even be relied upon? Will some other condition be put in place? Although I support Staff's concerns and agree that such analysis is most definitely warranted, it is unclear what outcome this will result in especially with projects that needs to begin construction as soon as possible to realize PTCs.

Q. Have you seen concerns similar to those that Staff has raised in cases in other states that are in SPP's footprint?

A. Yes. In Case No. EO-2018-0092 I spoke at length about AEP's 2GW Windcatcher Wind Farm that then had open dockets in Texas, Oklahoma, Arkansas and Louisiana. Parties in those cases raised concerns in the aforementioned states in contested cases surrounding Windcatcher that are similar to the concerns Staff has raised here.

Q. What happened to AEP's 2GW Windcatcher Wind Farm?

A. The Texas Public Utility Commission rejected American Electric Power's (AEP) application in total; thus, ending that proposal.

[17] EA-2019-0010 Staff Rebuttal Report, p. 37, 27-28.

Q. Why?

A. Because of the risks to ratepayers of AEP's projections being wrong.[18]

Q. Is it not better for Empire's wind projects that Windcatcher will not be selling wind energy into the SPP market?

A. Yes. However, AEP is still moving forward with wind projects that would ultimately compete with Empire's wind farm projects. Six months after Texas rejected its application, AEP released a request for proposal for up to 1.2 GWs of wind resources.[19]

Q. What CCN conditions is Staff proposing?

A. Staff witness Dietrich lists the following conditions:

1. Implementation of the Market Protection Provision as proposed in Appendix A to the non-unanimous Stipulation and Agreement between Empire, MECG, Staff, Renew Missouri Advocates, and DE filed on April 24, 2018 in Case No. EO-2018-0092 with the following changes:

    a. Remove the guarantee cap which was a negotiated value equal to $35 Million;

    b. Limit the value of PPA_Replacement to the amount calculated based upon the number of MWh generated to produce RECs in order to comply with the RES;

    c. Incorporate mutually agreeable provisions to adequately balance risks and performance related to Transmission Congestion Rights ("TCRs") and Auction Revenue Rights ("ARRs") related to the Neosho Ridge interconnection point to Empire's load serving area;

    d. inclusion of network interconnection costs in the revenue requirement for each project.

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[18] See GM-1.

[19] Morehouse, C. (2018) AEP seeks 1.2 GW of wind proposals, nearly six months after canceling $4.5B WindCatcher. *UtilityDive*. https://www.utilitydive.com/news/aep-seeks-12-gw-of-wind-proposals-nearly-six-months-after-canceling-2-gw/545589/

2. Completion of the SPP Definitive Impact System Impact Studies;

a. Empire will demonstrate that the outstanding studies do not raise any new issues, and if they do, that the Commission is satisfied with Empire's solution to address those issues.

3. Completion, and subsequent filing with the Commission, of a sensitivity analysis on curtailment and the dispatching down of each Wind Project;

a. Empire will demonstrate that the analysis does not raise any new issues, and if it 1 does, that the Commission is satisfied with Empire's solution to address those 2 issues.

4. Filing of the construction-level plans and specifications prior to commencing construction of each project;

a. If the specifications materially change from those contained in the Applications, Empire must file an updated application for the Wind Project(s).

5. Filing of the evidence of all required permits and approvals of affected governmental bodies outlined in Empire's response to Staff Data Request 0029;

6. Empire's commitment to cap the total network upgrade costs for which recovery may be 10 sought at Empire's estimate plus 10% contingency;

7. Use of the in-service criteria contained in attached Schedule CME-r1 to determine whether the projects are in-service.[20]

Q. What is your response to Staff's proposed CCN conditions?

A. I am encouraged by the fact that Staff is recognizing the risk exposure inherent in these wind farm projects, and Staff's recognition that the Market Protection Plan it agreed to in Case No. EO-2018-0092 is inadequate. However, Staff's conditions do not reduce the uncertainty regarding the costs of the projects, revenues to be received due to the projects, the amount of generation of the projects, or the financing of the projects. Staff's conditions just reduce the

[20] Ibid. p. 37, 10-28 & p. 38, 1-13

amount of economic harm to the captive ratepayers for ten years, 1/3 of the estimated life of these wind farms.

III. RESPONSE TO ECONOMIC BENEFITS

Q. Do you share the belief that the projects will result in local benefits to the public, specifically: payments to landowners, job creation, increase in tax revenue and economic benefits for Missouri counties with higher poverty rates as justification for Empire's wind farm projects?

A. I agree that the local economy would see a short-term gain for approximately 18 months as the projects are undergoing construction, and the projects will create approximately twenty permanent Missouri jobs. However, I disagree with the premise that the local economy as a whole will benefit from lease payments and tax revenues because the local economy, i.e. Empire's customers, will be funding those lease payments and tax revenues. In other words, the lease payments and tax revenues will be a wealth transfer from within the region. Moreover, Empire's Missouri ratepayers will be paying the lion's share of the Kansas taxes and payments-in-lieu-of-taxes because of the Kansas Neosho Wind Farm since Empire's Missouri customer base is much larger than Empire's Kansas customer base.

Q. Have you quantified the taxes and PILOT impact on Empire's Missouri ratepayers?

A. No, but I know what Empire modeled. Property taxes and/or Payments In Lieu Of Taxes ("PILOTs") are costs included in the operation and maintenance ("O&M") input in Empire's Levelized Cost of Energy ("LCOE") calculation. The aggregate of the forty-years totals Empire assumed for the two Missouri wind farms—Kings Point and North Fork Ridge is ** ** For the Kanas Neosho Ridge wind farm Empire assumed a 40-year total of ** **. However, the Kansas amount is currently in-flux and not finalized. **

**

Q. Is there anything else of which the Commission should be aware regarding taxes or PILOTs?

A. There is still a lot of uncertainty surrounding both taxes and PILOTs, especially as it pertains to Kansas. **

Q.

A.

Q.

A.

[21] See GM-2

**

Q. Does OPC oppose the Green Tariff concept?

A. Of course not. OPC has worked with many of the same stakeholders to put forward acceptable Green Tariff's related to potential wind projects and tariffs for community solar programs for both KCPL and Ameren Missouri. In each case, there were important customer protections put in place to minimize risk to nonparticipants in the event that the offering did not materialize as modeled.

Q. What sort of customer protections did the Commission approve in those Green Tariff cases?

A. In Ameren Missouri's Green Tariff Case No. ET-2018-0063, the parties agreed to risk-sharing provisions, which included Ameren Missouri shareholders bearing the first fifty percent of undersubscription program capacity (whether positive or negative), alleviating much of OPC's stated concerns in that case.

Parties also stipulated to Green Tariffs that the Commission later approved in Case No. ER-2018-0145 and ER-2018-0146 for Kansas City Power and Light Company ("KCPL") and KCP&L Greater Missouri Operations ("GMO"). In those cases, the companies agreed to shareholders bearing all of the risk attributed to the unsubscribed program capacity.

Parties agreed to a Solar Subscription Rider in which KCPL and GMO shareholders agreed to bear the first 75% of unsubscribed program capacity and ratepayer's bearing the remaining 25% of unsubscribed program capacity.

Q. Are there any similar protections proposed in this case?

A. No. There has been nothing approaching the Ameren Missouri, KCPL or GMO consumer protections regarding the procurement of renewable energy not necessary for providing safe and adequate service or meeting the state's RES requirements. As stated earlier, the market protection plan from Case No. EO-2018-0092 has been alluded to in various testimony, but the actual or amended plan has not been introduced to date, nor has what has been put forward been comparable in terms to the consumer protections realized by Ameren Missouri, KCPL and GMO customers.

Q. Putting aside consumer protections, are Ameren Missouri, KCPL and GMO's Green Tariff's comparable to Empire's applications here in terms of risk exposure?

A. No. Even without the consumer protections agreed to in the Green Tariff cases, those applications were predicated on actual contractual committed demand for the service before it could move forward. In contrast, Empire models its application on an assumed demand for this intermittent generation materializing in the future at a premium price. This difference cannot be understated.

Q. Does this conclude your testimony?

A. Yes

Control Number: 47461

Item Number: 455

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PUC DOCKET NO. 47461
SOAH DOCKET NO. 473-17-5481

2018 AUG 13 AM 10:30

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE WIND CATCHER ENERGY CONNECTION PROJECT IN OKLAHOMA	§ § § § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Southwestern Electric Power Company (SWEPCO) for a certificate of convenience and necessity (CCN) to authorize it to acquire, develop, and own a wind generation facility with a nameplate capacity of 2,000 megawatts (MW) and a 765-kilovolt (kV) generation tie-line to transmit electric energy from the Oklahoma Panhandle to eastern Oklahoma (together, the project). SWEPCO proposed to own 70% of the project, with the remaining 30% to be owned by its affiliate, Public Service Company of Oklahoma (PSO). SWEPCO also requested a good-cause exception to 16 Texas Administrative Code (TAC) § 25.236 to allow it to treat the costs associated with the project as a fuel expense and the federal production tax credit as a credit against the fuel expense. In addition, SWEPCO requested Commission approval to defer for ratemaking purposes a portion of the federal production tax credits into a regulatory liability to be credited back to consumers starting 11 years after the project begins operation. Finally, SWEPCO also filed an application under PURA § 14.101 but argued that section does not apply to this proceeding. In the alternative, SWEPCO requested a public interest finding under that section if the Commission were to find that PURA § 14.101 applies.

The Commission referred the application to the State Office of Administrative Hearings (SOAH) and a hearing on the merits was held on February 13 through February 22, 2018. On May 18, 2018, the SOAH administrative law judges (ALJs) issued a proposal for decision (PFD) in which they recommended approval of the application with certain guarantees to protect consumers if the project does not realize the benefits anticipated in the PFD assessment. After exceptions and replies to exceptions were filed by many of the parties, the ALJs issued a letter on July 6, 2018 making changes to some assumptions used in their analysis that reduced the amount

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of estimated benefits presented in the PFD, but did not change their recommendation to approve the application. The ALJs recommended changes to findings of fact 90, 92, 101, 109, and 123 through 125.

The Commission disagrees with the ALJs' recommendation to approve the application. The Commission finds that SWEPCO did not meet its burden of proof in this proceeding. Based on the evidence admitted in this proceeding, the Commission finds that SWEPCO failed to show that the project will lead to the probable lowering of cost to SWEPCO's consumers and, consequently, that it failed to show that the project is necessary for the service, accommodation, convenience, or safety of the public under PURA § 37.056.[1] Accordingly, the Commission must deny the application and does so for the reasons discussed in this Order. In addition, the Commission adopts only those portions of the PFD as specified in this Order.

I. Discussion

Under PURA § 37.056, the Commission may grant a certificate of convenience and necessity only if the Commission finds it is necessary for the service, accommodation, convenience, or safety of the public. In evaluating whether to grant an application under that section, the Commission must consider certain factors, including the probable lowering of cost to consumers.[2] SWEPCO acknowledged in its application, and all parties in this docket agree, that this project is not needed to meet increased load or address capacity issues and that service is adequate. Instead, SWEPCO stated that it filed this application because it believes this project will provide savings to its consumers.[3] Because the project is located entirely outside of the state of Texas, the ALJs concluded that the Commission should not evaluate the site-specific factors listed in PURA § 37.056, such as community, historical, and aesthetic values.[4] Thus, while the ALJs did address other factors,[5] the main focus of this proceeding and the PFD was a single factor: whether the project would result in the probable lowering of cost to consumers.

[1] Tex. Util. Code Ann. §§ 11.001–58.302 (West 2016 & Supp. 2017), §§ 59.001–66.016 (West 2007 & Supp. 2017 (PURA).

[2] *See* PURA § 37.056(c).

[3] PFD at 2.

[4] *Id.* at 2, 65.

[5] *See* Finding of Fact Nos. 13–18.

The burden of proof in this proceeding resides with SWEPCO, the applicant, to prove that the project is necessary for the service, accommodation, convenience, or safety of the public. SWEPCO calculated the purported benefits of the project, the lowering of cost to consumers, based on certain assumptions. It estimated the likely amount of benefits to consumers over the life of the project to be $1.495 billion on a net-present-value basis.[6]

The ALJs adjusted three of SWEPCO's assumptions[7] and found that the amount of purported benefits was significantly lower than what SWEPCO estimated but still concluded that some benefits were likely to occur.[8] Because of this lower amount of benefits, the ALJs recommended certain protections for consumers, including a guarantee of 100% of the production tax credits that SWEPCO would receive based on the actual output of the facility with an exception for changes in law, a guarantee of a cost cap of 103% of the estimated costs of the project, and a guarantee of a 44.7% net capacity factor without an exception for force majeure or change in law.[9]

Other parties in this case vigorously disagreed with the assumptions used by SWEPCO in its analysis. Using different assumptions, they found that the project would not lead to a probable lowering of cost to consumers and, indeed, could lead to a net cost to consumers. One intervenor, the Office of Public Utility Counsel (OPUC), argued that the net cost could be $912 million,[10] another intervenor, Texas Industrial Energy Consumers (TIEC), argued that the net cost could exceed $1 billion,[11] and yet another intervenor, Cities Advocating Reasonable Deregulation (CARD), argued that the net cost to consumers could be $1.971 billion.[12]

The parties in this case raised many issues in challenging SWEPCO's estimates regarding the costs of the project. SWEPCO's own witness stated that for every 1% of capital-cost overrun, the net present value of the project's benefits would decrease by $30 million.[13] Commission Staff's

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[6] PFD at 2, 8.

[7] *Id.* at 8–9, 29–30, 33, 36–37.

[8] *Id.* at 2.

[9] *Id.* at 59-61; ALJs' Exceptions Letter at 2–4 (July 6, 2018).

[10] OPUC's Reply to Exceptions to the Proposal for Decision at 5 (June 25, 2018).

[11] TIEC's Reply to Exceptions to the Proposal for Decision at 4 (June 25, 2018).

[12] CARD's Exceptions to the Proposal for Decision at 13 (June 12, 2018).

[13] Tr. at 1049:14–17 (Pearce Cross) (Feb. 20, 2018).

witness testified that no facility study has been conducted by the Southwest Power Pool (SPP) and without such a study, the full costs of the project are not sufficiently known to provide an adequate cost-benefit analysis.[14] Evidence also showed that because of the length and location of the generation tie-line, difficulty in acquisition of rights-of-way and exposure to weather-related events may occur, which could add delay and additional cost to the project,[15] either of which would lower any projected benefits of the project.

The other parties also raised many issues that cast doubt on the assumptions SWEPCO used to evaluate the economics of the project. A central issue of this case is the forecasted price of natural gas. SWEPCO used an in-house analysis called the *fundamentals forecast*, which was provided to all American Electric Power (AEP) companies in October 2016. The ALJs found SWEPCO's base-case assumption, at a levelized price of $7.35 per million British thermal units (MMBtu), to be too high and based on an out-of-date forecast.[16] Instead, the ALJs used the levelized Energy Information Administration (EIA) 2018 reference forecast of $5.32 per MMBtu.[17] Because a decrease of $1 per MMBtu in gas prices would reduce the estimated base-case savings of the project by approximately $392 million on a net-present-value basis, the ALJs reduced the estimated amount of benefits of the project by $678 million.[18]

Other parties put forth evidence showing that in recent Commission proceedings, lower gas prices were used that are more aligned with the New York Mercantile Exchange (NYMEX) futures pricing, which represents actual transactions between buyers and sellers who put real money at risk in their day-to-day operations.[19] In Docket No. 46936,[20] the Southwestern Public

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[14] Direct Testimony of David Smithson, Commission Staff Ex. 3A at 10.

[15] Tr. at 231–233, 669–674 (Weber Cross) (Feb. 13, 2018); Staff Ex.3A at 6 (Smithson Direct); Direct Testimony of Jeffry Pollock, TIEC Ex.1 at 42; TIEC's Initial Brief at 16–17.

[16] PFD at 29.

[17] *Id.* at 29–30; ALJs' Exceptions Letter at 2.

[18] *Id.*

[19] TIEC Ex. 1 at 14 (Pollock Direct).

[20] *Application of Southwestern Public Service Company for Approval of Transactions with ESI Energy, LLC, Invenergy Wind Development North America LLC, to Amend a Certificate of Convenience and Necessity for Wind Generation Projects and Associated Facilities in Hale County, Texas and Roosevelt County, New Mexico and for Related Approvals*, Docket No. 46936, Supplemental Settlement Testimony of David T. Hudson on Behalf of Southwestern Public Service Company (Apr. 19, 2018).

Service Company (SPS), in its low-gas-price forecast, projected a levelized price of natural gas at \$3.55 per MMBtu, and in Docket No. 46416,[21] Entergy Texas, Inc. (ETI) projected \$3.68 per MMBtu.[22] The NYMEX futures price, when trended to 2045, of \$3.58 per MMBtu was also well below SWEPCO's forecast.[23] EIA's lowest gas-price case, at \$4.12 per MMBtu, was also suggested by OPUC because, as noted by the ALJs, it has been the forecast that has more closely tracked the actual prices of natural gas for the last several years.[24] Using either EIA's lowest gas-price case or the SPS's low gas-price forecast, intervenors argued that the net present value of the project's projected benefits would be reduced by over \$1 billion.[25]

Gas-price forecasts were not the only contested factor used in evaluating the economics of the project. The ALJs also reduced the amount of benefits of the project by \$550 million to remove the costs related to an assumed future carbon tax used in SWEPCO's modeling.[26] Other parties strongly criticized this assumption and associated costs, and the ALJs concluded that such costs were not supported by the evidence, stating "there was no credible evidence to show that the imposition of such a carbon tax is likely in the future."[27]

The ALJs also found that approximately 6,000 MW of new wind generation have pending or completed generation interconnection agreements and are likely to be deployed in the SPP footprint, which would decrease the net present value of the project by \$76 million.[28] TIEC presented evidence that the SPP interconnection queue includes an additional 10,000 MW of wind projects in the SPP Facility Study Stage, which is one step away from a generation interconnection agreement, and another 24,000 MW are in the Definitive Interconnection System Impact Study

[21] *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Montgomery County Power Station in Montgomery County*, Docket No. 46416 (Oct. 7, 2016).

[22] TIEC Ex. 1 at 12 (Pollock Direct).

[23] *Id.*

[24] OPUC's Exceptions to the Proposal for Decision at 8 (June 12, 2018); PFD at 28.

[25] *See* TIEC Ex. 1 at 51 (Pollock Direct) (using the SPS low gas case would lead to a reduction of \$1.141 billion in benefits); OPUC's Exceptions at 8 (using EIA lowest gas-price case would lead to a reduction of \$1.266 billion).

[26] PFD at 33.

[27] *Id.*

[28] ALJs' Exceptions Letter at 2–3.

Stage.[29] TIEC advocated for assuming a portion, 14,000 MW, of that interconnection queue will be developed, which would decrease the estimated benefits of the project by $499 million.[30]

Another of SWEPCO's assumptions regarding the benefits of the project challenged by the other parties is the project's assumed net capacity factor. Based on studies performed by independent consulting firms, SWEPCO assumed a 51.1% net capacity factor at a P50 estimate, which means there is a 50% likelihood that the actual output will be greater and a 50% likelihood that the actual output would be less than 51.1%.[31] SWEPCO also acknowledged that each 1% reduction in net capacity factor would lead to a $95.6 million reduction in the net present value of the project benefits.[32] Other parties raised issues with the process used by the consulting firms to reach the 51.1% assumption and concerns about the availability of the generation tie-line, which would affect the actual net capacity factor.[33] Additionally, SWEPCO was not willing to guarantee the full 51.1% net capacity factor, placing the risk of underperformance on the consumers.

SWEPCO's assumption of the future capacity value of the wind facility was also contested. SWEPCO contended that the project will allow it to defer the construction of two natural gas combined-cycle units during the life of the project, and to account for this deferral, it included $269 million in its calculation of project benefits. The ALJs noted that much of the proceeding is based on projections and that SWEPCO's estimate of capacity value was reasonable.[34] Intervenors argued that this amount of capacity value is supported by minimal testimony and is dependent on a number of unknown and speculative factors.[35]

The ALJs also identified, but did not quantify, several issues for the Commission to consider that could affect the benefits of the project. First, the ALJs noted that the contingency percentage in the contract with the wind-facility developer was low, at only 3.2% of the total cost

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[29] TIEC Ex.1 at 27–28 (Pollock Direct).

[30] TIEC Exceptions at 35.

[31] PFD at 38.

[32] Tr. at 1050–51 (Pearce Cross) (Feb. 20, 2018).

[33] TIEC Ex.1 at 44–45 (Pollock Direct); Commission Staff Ex. 3A at 6–9 (Smithson Direct).

[34] PFD at 45.

[35] Tr. at 1235–1236 (Pollock Direct) (Feb. 21, 2018); PFD at 45.

of the wind facility.[36] Also, the ALJs determined that, as mentioned above, because of the length and location of the generation tie-line, the difficulty in acquiring right-of-way and the exposure to weather-related events may add delay and additional cost to the project.[37] Third, the ALJs noted that SWEPCO's analysis of additional reserve costs due to the project was not reliable or convincing.[38] Fourth, the ALJs stated that the effect on project benefits from additional wind generation may be understated, because SWEPCO's congestion costs, which have an impact on the locational marginal pricing calculation, are likely too high due to a reliance on the natural gas prices in AEP's fundamentals forecast.[39] Fifth, SWEPCO did not offer to guarantee that consumers would receive the full benefits of the production tax credits in the event that a change in law were to occur, and the ALJs noted that the Commission may wish to consider the effect that a change in law would have on its decision.[40] The Commission takes note of these issues and finds that they add additional uncertainties in the projected benefits and further show that SWEPCO has failed to prove the project will lead to a probable lowering of cost to its consumers.

As mentioned above, the ALJs calculated their projection of potential benefits to consumers and found it insufficient without implementing certain guarantees to protect consumers.[41] In rebuttal testimony, SWEPCO offered various conditions to act as hedges against some of the cost risks of the project.[42] Intervenors also proposed different, more stringent guarantees to protect consumers.[43] In the PFD, the ALJs rejected some proposed guarantees and decided to recommend the following four guarantees: first, two cost caps recommended by Commission Staff, one for the cost of the wind facility and the other for the cost of the project, without exceptions for force majeure and change in law;[44] second, a 30-year life span for the

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[36] PFD at 18.

[37] *Id.* at 19.

[38] *Id.* at 19.

[39] *Id.* at 37.

[40] *Id.* at 44.

[41] *Id.* at 2.

[42] *Id.* at 47.

[43] *Id.* at 56–59.

[44] PFD at 59–60, Proposed Finding of Fact No. 125; *see also* PFD at 48 (discussing Commission Staff's proposal).

depreciation rate of the project;[45] third, a net capacity-factor guarantee of 44.7% without exceptions for force majeure or change in law;[46] and fourth, a guarantee that consumers would receive 100% of the production tax credits that SWEPCO would receive based on a 51.1% net capacity factor with an exception for changes in law.[47] The ALJs rejected a base-case gas-savings guarantee and SWEPCO's 10-year look-back guarantee because they would not properly protect consumers due, in part, to inaccuracies and uncertainties in the methodologies.[48]

After exceptions were filed, the ALJs filed a letter recommending two changes to the guarantees they implemented in the PFD: they changed the project cost cap to 103% on a company-wide basis and clarified that the production tax credit guarantee applied only to the actual output of the facility, not at a 51.1% net capacity factor.[49]

At the Commission's July 12, 2018 open meeting, the Commissioners requested that the parties attempt to reach agreement on the issue of guarantees to protect consumers. Following the open meeting, the parties made various filings that indicated no agreement had been reached between SWEPCO and the other parties in this case regarding the guarantees.

The Commission finds that the guarantees set forth in the PFD and the ALJs' exceptions letter do not sufficiently protect consumers because they do not provide enough certainty of a probable lowering of cost to consumers.

The Commission in this Order does not address the accuracy or reasonableness of any individual assumption made by any party that underlies their analyses in this docket regarding whether this project will provide benefits to consumers. The Commission notes the many assumptions, the range in values of the parties' assumptions, and the significant range of benefits or costs to consumers presented by the parties, ranging from SWEPCO's $1.495 billion in benefits to OPUC's $912 million in costs, TIEC's $1.1 billion in costs, and CARD's $1.971 billion in costs. The bulk of the evidence in this proceeding casts doubt on the assumptions SWEPCO, who bears

[45] PFD at 60, Proposed Finding of Fact No. 140.

[46] PFD at 61; Proposed Findings of Fact Nos. 126–28.

[47] PFD at 61–62, Proposed Findings of Fact Nos. 129–31.

[48] PFD at 60–61, 62, Proposed Findings of Fact Nos. 33–37.

[49] ALJs' Exceptions Letter at 3–4.

the burden of proof, used to determine that benefits to consumers are probable. The Commission need not choose a single number within this range given the uncertainty of assumptions and the magnitude of the risk that could be imposed upon consumers. In addition, sufficient consumer safeguards have not been offered by SWEPCO that would allow the Commission to conclude there is a probability of benefits to consumers from the project.

For the reasons discussed in this Order, the Commission finds that SWEPCO failed to show that it is probable the project will lead to lower cost for consumers and, consequently, the Commission cannot approve the application. The Commission disagrees with the PFD's conclusion and finds that SWEPCO has failed to show that the project is likely to lead to lower cost for consumers. Accordingly, the Commission adopts those portions of the PFD, including findings of fact and conclusions of law, that address procedure and the positions and arguments of the parties, and other portions consistent with this Order and the decision of the Commission.

To reflect its decision in this matter, the Commission deletes as either unnecessary or incompatible with its decision findings of fact 24, 33, 43, 51 through 56, 58, 59, 74, 85 through 88, 98, 100, 102, 107, 108, 121, 127, 128, 130, 131, 139, 145, and 149, and conclusions of law 4 and 10; modifies findings of fact 60, 83, 84, 89, 99, 105, and 136 and conclusions of law 1, 7, and 11; and adds new findings of fact 50A, 60A, 77A, 92A, 99A, 106A, 109A, and 139A and new conclusion of law 10A.

Findings of fact 90 and 123 are modified and finding of fact 125 is deleted as recommended by the ALJs in their July 6, 2018 letter. The Commission deletes as either unnecessary or incompatible with its decision findings of fact 92, 101, 109, and 124, which also included modifications recommended by the ALJs.

Due to the Commission's decision above, the Commission does not address SWEPCO's request for a good-cause exception to 16 TAC § 25.236, SWEPCO's request to defer a portion of the federal production tax credits into a regulatory liability, SWEPCO's likelihood of obtaining the full amount of the production tax credits, the additional guarantees proposed by intervenors, the effect that approving the application would have on Lubbock Power & Light's or Rayburn Country Electric Cooperative's proposal to become part of the Electric Reliability Council of Texas, or the applicability of PURA § 14.101 to this proceeding. Therefore, it does not adopt the

PFD on these issues and deletes findings of fact 19, 110 through 118, 140 through 144, 148, and 150 through 158 and conclusions of law 5 and 8.

Finally, the Commission also makes non-substantive changes to the findings of fact and conclusions of law for such matters as capitalization, spelling, grammar, punctuation, style, correction of numbering, and readability.

The Commission adopts the following findings of fact and conclusions of law:

II. Findings of Fact

Background and Procedural History

1. SWEPCO is a wholly owned subsidiary of AEP and is a fully integrated electric utility serving retail and wholesale consumers in Texas, Arkansas, and Louisiana.

2. On July 21, 2017, SWEPCO filed an application with the Commission to amend its CCN to authorize acquisition of an interest in the project to be located in Oklahoma. The application also requested preapproval of various ratemaking treatments to recover the project costs from SWEPCO's consumers.

3. The Commission referred the application to SOAH on August 2, 2017.

4. SWEPCO provided notice of the application by publication once a week for two consecutive weeks in a newspaper having general circulation in each county in SWEPCO's service territory. SWEPCO's notice by newspaper publication was completed on September 9, 2017.

5. SWEPCO provided notice to SWEPCO's Texas retail consumers by bill insert, which was completed on September 26, 2017.

6. SWEPCO provided individual notice to Commission Staff and OPUC by hand-delivering a copy of SWEPCO's filing to each party's counsel. Individual notice was also provided to the legal representative of all parties in Docket No. 46449, SWEPCO's last base-rate case, and Docket No. 42527, SWEPCO's most recent fuel reconciliation proceeding. Individual notice was completed on July 31, 2017.

7. The following parties intervened and participated in this docket: TIEC; OPUC; Golden Spread Electric Cooperative, Inc.; East Texas Electric Cooperative, Inc. and Northeast

Texas Electric Cooperative, Inc.; Wal-Mart Stores Texas, LLC and Sam's East, Inc.; CARD; South Central MCN, LLC; and Tri-County Electric Cooperative, Inc..

8. On August 18, 2017 in SOAH Order No. 2, the SOAH ALJ established the procedural schedule and issued notice of the time and place of the hearing.

9. The Federal Tax Cuts and Jobs Act (TCJA) was signed into law on December 22, 2017, with an effective date of January 1, 2018.

10. On January 17, 2018, SWEPCO filed a motion to postpone taking evidence until January 22, 2018 because, after further study of the TCJA, SWEPCO determined that certain testimonies and exhibits would need to be amended or supplemented to reflect accurately the impact of the TCJA.

11. The hearing on the merits was held on February 13 through 16 and on February 20 through 22, 2018.

12. The record closed on April 30, 2018, following the admission of evidence to update the status of the regulatory proceedings in other jurisdictions.

CCN Issues

13. The investment in the project will have a significant impact on SWEPCO's finances.

14. Because the project will be located entirely within the state of Oklahoma, there will be no adverse effects on any other electric utility in Texas.

15. There will be no adverse effect on community values, recreational and park areas, historical and aesthetic values, or environmental integrity in Texas because the project is located entirely within the state of Oklahoma.

16. Because there is no need for the project to serve retail load, the addition of the project will not improve service.

17. Texas has already met its renewable energy goals, so the project will have no effect on those goals.

18. SWEPCO is not currently in the process of implementing customer choice in its service territory.

19. DELETED.

Analysis of Economics of Wind Catcher (PO Issues 10, 12, 14, 25, 26)

20. SWEPCO contends that consumers will experience $1.495 billion in net benefits using its base-gas-price case (which it believes is the correct case to use), $1.114 billion in net benefits under its low-gas-price case, and $1.932 billion in benefits under the high-gas-price case.

Project Description and Cost (PO Issues 10 and 12)

21. The project consists of the Wind Catcher generation tie-line and a wind facility with 800 General Electric model 2.5-MW wind-turbine generators that would provide 1,900 MW of delivered and 2,000 MW nameplate wind energy. The total estimated project costs, including allowance for funds used during construction are set forth in the table below:

	SWEPCO (billions)	**TOTAL (billions)**
WIND FACILITY	$2.031	$2.902
GENERATION TIE-LINE	$1.137	$1.624
PROJECT (BOTH)	$3.168	$4.526

22. The wind facility is being constructed by Invenergy Wind Development North American LLC, which commenced construction in 2016 and has continuously maintained construction.

23. Invenergy has targeted completion of the wind facility for September 30, 2020.

24. DELETED.

25. On July 26, 2017, the developers and participants in the wind facility entered into an agreement entitled the Membership Interests Purchase Agreement (MIPA) to acquire, subject to regulatory approvals and other conditions, States Edge Wind I LLC, an Invenergy single-purpose subsidiary that will own the rights and assets of the wind facility.

26. The MIPA is a fixed-price arrangement whereby Invenergy will manage all phases of construction and deliver the wind facility upon completion to SWEPCO and PSO. Invenergy will pay all construction financing costs, which are included in the purchase price.

27. The purchase price for the wind facility is $2.694 billion. The total estimated cost, including the MIPA purchase price and other cost components, is $2.902 billion. SWEPCO's share is approximately $2.031 billion.

28. The generation tie-line would deliver the wind facility's energy directly to the AEP load zone, bypassing congestion and curtailment on the SPP system in western Oklahoma.

29. The generation tie-line would consist of a proposed 345-kV-to-765-kV generation substation at the wind facility; a proposed 350-to-380-mile, radial, single-circuit 765-kV transmission line; and a proposed 765-kV to 345-kV substation, which is in the Tulsa AEP load zone.

30. The purpose of the generation tie-line is to transmit the wind facility's energy from western Oklahoma to the Tulsa AEP load zone.

31. The participating utilities have entered into a fixed-price contract with Quanta Services, a Houston company, for engineering, procurement, and construction services for the generation tie-line.

32. Under the Quanta contract, all engineering, procurement, and construction are covered under the scope of Quanta's work.

33. DELETED.

34. The total estimated capital cost for the generation tie-line is $1.624 billion including $148 million for allowance for funds used during construction. SWEPCO's share of the estimated total cost would be 70%, or $1.1 billion.

35. The generation tie-line has a projected completion date of December 15, 2020.

36. The generation tie-line's projected completion date is slightly more than two weeks before the end of the Internal Revenue Service (IRS) safe-harbor date for wind-production tax credits.

37. Production tax credits are assured for projects in service before the safe-harbor date. Projects that enter into service later may still receive the credits, but must show they meet certain criteria.

38. If the project were to be built on budget, it would increase SWEPCO's rate base established in its most recent rate proceeding by over 72%, leading to a base-rate increase in Texas of at least $150 million in 2021, depending on the timing of a rate case.

39. Although the MIPA includes a provision for contingencies, that amount is $93.3 million, which is only 3.2% of the total wind facility cost.

40. The generation tie-line cost is not guaranteed, but is subject to increases based on a number of factors, including the cost to acquire land (including the cost of possible eminent domain proceedings), internal labor and overhead, allowance for unknown risks, and allowance for funds used during construction.

41. Including those additional costs, the generation tie-line is anticipated to cost a total of $1.624 billion.

42. The generation tie-line contract price is set with limited reopeners, a stringent process for obtaining change orders, and numerous contractual protections.

43. DELETED.

44. The contract with Quanta provides exceptions to the definition of a force majeure event by excluding weather events that are normal weather for the period, season, and geographic area of the generation tie-line except to the extent that such normal weather causes physical damage to towers or the work in progress.

45. If weather that does not cause physical damage occurs, the contractor must provide climatological data over the preceding five years substantiating that the weather conditions were unusually adverse for the period of time and location based on historical data and could not have been reasonably anticipated.

46. The contract with Quanta requires the contractor to spend up to $5 million to mitigate damage to the generation tie-line work and any delay in the project schedule's critical path before claiming additional compensation. It also includes a provision requiring an expedited schedule if a force majeure event creates any delay.

47. SPP's practice in calculating the operating reserve requirement is to base it on 100% of the largest SPP generating unit, plus 50% of the second largest.

48. If approved and built, the project would become the largest generating unit in the SPP system.

49. Although SWEPCO believes that the effect on reserves costs would be only a little over $200,000, it based its estimate on SPP setting the requirement on an hourly basis.

50. SPP currently sets the reserve requirement on a daily basis.

50A. No facility study has been conducted on the project by SPP.

51. DELETED.

52. DELETED.

53. DELETED.

54. DELETED.

55. DELETED.

56. DELETED.

57. The generation tie-line contract is a fixed-cost agreement, with certain additional costs to be determined.

58. DELETED.

59. DELETED.

60. The length and location of the generation tie-line raise greater possibilities of additional delays and costs.

60A. For every 1% in capital cost over-run, the net present value of the project's benefits calculated by SWEPCO would be decreased by $30 million.

61. The record does not include a reliable calculation of the reserve costs based on a daily calculation.

Economic Evaluation Methodology and Assumptions (PO Issues 12 and 14)

Evaluation Methodology

62. To evaluate the economics of the projects, SWEPCO developed and compared three cases—three alternative resource procurement paths.

63. The first case—the base case—assumed no new development or purchase of any wind resources between 2021 and 2045. The second case—the project case—reflected the development of the project.

64. To determine the estimated benefits of the project, SWEPCO compared the difference between the base case and the project case for the period modeled, 2021 to 2045.

65. The third case—the generic wind case—assumed the procurement of 1,900 MW of wind generation at 24 different wind sites across SPP.

66. SWEPCO estimated that the project would produce approximately $685 million more in customer savings than the generic wind case would relative to the base case.

67. The three cases were modeled using PROMOD® and PLEXOS® simulation tools to estimate the production-related costs and benefits of each case. SWEPCO used both models because neither was sufficient on its own to analyze the project's lifetime impact.

68. The PROMOD® model is available only for two years (2020 and 2025) and analyzed only cost impacts for individual SPP transmission zones such as the AEP zone, in the aggregate.

69. The PLEXOS® model does not simulate the entire SPP footprint and does not simulate transmission constraints or marginal losses. Therefore, SWEPCO input data for 2020 and 2025 into the PROMOD® model, interpolated between those two points, and then extrapolated that trend going outward for the life of the project.

70. SWEPCO used that data in PLEXOS® to estimate the costs and the benefits of the project for SWEPCO consumers.

71. SWEPCO and PSO, in the fall of 2016, issued a request for proposal soliciting bids to construct a wind-energy project.

72. The 2016 projects would have connected to the SPP system in congested areas and did not account for economic curtailment costs.

73. The competitive market would not have provided the project, and the timing of a request for proposal would have precluded the construction of the project in time to take full advantage of the production tax credits.

74. DELETED.

Assumptions Impacting Locational Marginal Prices

Natural Gas Prices

75. Future natural gas prices are an essential element of the project benefits calculation. The higher the expected future natural gas prices, the greater the expected benefits from the project.

76. SWEPCO used AEP's Long-Term North American Energy Market Forecast (fundamentals forecast) to forecast the expected project benefits.

77. The fundamentals forecast was made available to all AEP operating companies on October 27, 2016.

77A. The fundamentals forecast contained natural-gas-price projections for a base case, a high case, and a low case. The base case was used by SWEPCO to analyze the economics of the project. The base case used a levelized natural gas price of $7.35 per MMBtu.

78. Natural gas prices are important because fuel prices are a key component in determining the supply stack, or merit order, for the dispatch of generating units.

79. The 2016 fundamentals forecast employed a carbon dioxide dispatch burden on all existing fossil-fuel-fired generating units that escalated from $2.92 per ton in 2024 to $26.31 per ton in 2032 to achieve national mass-based emission targets similar to those proposed in the national Clean Power Plan.

80. Each of AEP's past forecasts, dating back to 2007, has been on the high side of actual natural gas prices.

81. Although the 2016 fundamentals forecast was weather-normalized, the evidence did not quantify the impact of abnormal weather on prior forecasts.

82. SWEPCO's forecasts start out higher than current prices and have been higher than actual prices for several years.

83. The gas prices of the SPS and ETI forecasts used in recent Commission proceedings were significantly lower than SWEPCO's fundamentals forecast. The SPS low case forecast projected a levelized price of natural gas at $3.55 per MMBtu. The ETI low case forecast projected a levelized price of natural gas at $3.68 per MMBtu.

84. The NYMEX futures prices represent actual transactions between buyers and sellers who put real money at risk in their day-to-day operations. The NYMEX futures prices, when trended to 2045, are $3.58 per MMBtu.

85. DELETED.

86. DELETED.

87. DELETED.

88. DELETED.

89. The lowest Energy Information Administration (EIA) case has been the most accurate in recent years.

90. The levelized natural-gas-price forecast from EIA's 2018 reference case for the years 2021 through 2045 is approximately $5.32 per MMBtu.

91. A decrease of $1 per MMBtu in gas prices would reduce the estimated base-case savings for the project by approximately $392 million net present value.

92. DELETED.

92A. The record in this proceeding fails to show that the assumptions made by SWEPCO regarding gas prices will result in a probable lowering of cost to consumers.

Cost of Carbon

93. SWEPCO's three cases employ a carbon dioxide dispatch burden (allowance price) on all existing fossil-fuel-fired generating units.

94. SWEPCO designed the carbon burden to achieve emission targets similar to those proposed in the federal Clean Power Plan.

95. In the base case, the carbon burden is zero in 2021 to 2023, then escalates from $2.92 per ton in 2024 to $26.31 in 2032.

96. Although it is possible that a carbon tax will be imposed in the future, such a tax has not been imposed in the past, there is not one in place now, and there was no credible evidence to show that the imposition of such a tax is likely in the future.

97. SWEPCO's modeling of the locational marginal prices should not have included the carbon-burden component, and the calculation of the estimated benefits of the project should be reduced accordingly.

98. DELETED.

Other Assumptions

99. SWEPCO's modeling understated the amount of new wind generation in SPP.

99A. The SPP interconnection queue includes an additional 6,000 MW of projects with pending or completed interconnection agreements, 10,000 MW of additional wind projects in the SPP Facility Study Stage, and another 24,000 MW in the Definitive Interconnection System Impact Study stage.

100. DELETED.

101. DELETED.

102. DELETED.

103. SWEPCO's calculated congestion costs are likely too high due to high estimated natural gas prices.

Net Capacity Factor

104. A crucial measure of generation output is the wind facility's net capacity factor, which is the ratio of the actual output of a generating unit over a period of time to its potential output at full nameplate capacity.

105. Based on the results of two studies, SWEPCO estimates a project net capacity factor of 51.1% at a P50 estimate, which means there is a 50% likelihood that the actual output will be greater and a 50% likelihood that the actual output would be less than 51.1%.

106. Each 1% reduction in net capacity factor would lead to a $95.6 million reduction in net present value project benefits, considering both production cost savings and lower production tax credits.

106A. If the generation tie-line is not available due to outages, maintenance, or force majeure events, the actual net capacity factor will be diminished.

107. DELETED.

108. DELETED.

Projected Benefits of Wind Catcher

109. DELETED.

109A. SWEPCO failed to provide evidence to show it is probable the project would provide a reduction in cost to consumers.

Production Tax Credits (PO Issues 25 and 26)

110. DELETED.

111. DELETED.

112. DELETED.

113. DELETED.

114. DELETED.

115. DELETED.

116. DELETED.

117. DELETED.

118. DELETED.

Capacity Value of the Wind Facility (PO Issue 14)

119. SWEPCO calculated the future capacity value of the wind facility and included that calculation, $269 million on a net-present-value basis, as one of the financial benefits of the project.

120. The forecasted incremental value was based on the deferral of a future natural gas combined-cycle (NGCC) unit from 2026 to 2033 and the avoidance of a second NGCC unit from 2038 through the end of the modeling period, 2045.

121. DELETED.

SWEPCO's Proposed Guarantees

122. SWEPCO proposed a cost cap for the wind facility, generation tie-line, and all SPP-assigned generation interconnection costs of $3.339 billion, which is 109% of the estimated cost of SWEPCO's 70% share of the project. This cost cap does not include allowance for funds used during construction.

123. In a settlement in Oklahoma, SWEPCO's sister company, PSO, agreed to a cost cap of 103% of project costs including allowance for funds used during construction, which is equivalent to $2,332 per kW of nameplate capacity as measured on a total parent-company gross-plant basis, without exceptions for force majeure or change of law.

124. DELETED.

125. DELETED.

126. SWEPCO proposed a guaranteed net capacity factor of 44.7%, which is 87% of the capacity projected in its application. This guarantee includes exceptions for force majeure and change in law.

127. DELETED.

128. DELETED.

129. SWEPCO's proposed production tax credit guarantee of eligibility for 100% of the production tax credits with exceptions for force majeure and change in law does not provide a sufficient guarantee to customers.

130. DELETED.

131. DELETED.

132. SWEPCO proposed to agree to flow to consumers 100% of the incremental off-system energy sales margins that would not have occurred but for the project and the net proceeds from the sale of renewable energy credits associated with the project.

133. SWEPCO proposed to agree to a 10-year look-back proposal based on the following formula:

> ***Net Benefit for Customers = Fuel Savings + Project Capacity Value + PTCs + Minimum Net Capacity Factor Guarantee Payments + RECs Value + Carbon Savings – Project Revenue Requirement***

134. If the net benefit for customers at the end of the ten-year period is positive, SWEPCO will not owe customers any compensation under this guarantee. If the net benefit calculation for customers at the end of the ten-year period is negative, SWEPCO will compensate customers for that amount under the formula.

135. SWEPCO's look-back proposal is unlikely to yield a calculation of savings given that the methodology does not look at the actual price on the SPP market, and instead looks at SWEPCO's bid stack to determine what SWEPCO's generation cost would have been had the resources been placed into the market.

136. SWEPCO's look-back proposal likely overstates customer benefits.

137. No other party presented sufficient evidence to adopt a different look-back proposal.

138. SWEPCO proposed a most favored nation guarantee such that, if terms more favorable to consumers are agreed to by PSO or SWEPCO in any of the state utility commission proceedings under which they are seeking approval of the project, SWEPCO would disclose the terms and incorporate them into the guarantees for the benefit of SWEPCO Texas consumers for the following: (1) the Gigawatt hours output of the production guarantee; (2) the production-tax-credit eligibility; or (3) the cost cap percentage.

139. DELETED.

139A. The guarantees offered by SWEPCO are not sufficient to protect consumers from the risk of the project.

Commission Staff or Intervenor Proposed Guarantees

140. DELETED.

141. DELETED.

142. DELETED.

143. DELETED.

144. DELETED.

Other CCN Issues

145. DELETED.

146. The project is located entirely outside of the State of Texas, and Texas' community values, parks, historical sites, and environment are unaffected.

147. Texas has met its renewable energy goals.

148. DELETED.

CCN for Economic Purposes

149. DELETED.

Ratemaking Treatments

150. DELETED.

151. DELETED.

152. DELETED.

153. DELETED.

154. DELETED.

155. DELETED.

156. DELETED.

157. DELETED.

158. DELETED.

III. Conclusions of Law

1. The Commission has jurisdiction over this application under PURA §§ 36.203, 36.204, 37.051, 37.053, 37.056, and 37.057.

2. SOAH has jurisdiction over this proceeding, including the preparation of this proposal for decision with findings of fact and conclusions of law under PURA § 14.053 and Texas Government Code § 2003.049.

3. Notice of the application was provided in compliance with PURA § 37.054 and 16 Texas Administrative Code (TAC) § 22.55.

4. DELETED.

5. DELETED.

6. SWEPCO is not implementing customer choice under PURA §§ 39.501(b) and 39.502(b) and 16 TAC § 25.422(e).

7. SWEPCO has not shown that the project will result in the probable lowering of cost to consumers in accordance with PURA § 37.056(c)(4)(e).

8. DELETED.

9. Texas has met its renewable energy goals under PURA § 39.904(a).

10. DELETED.

10A. SWEPCO has not met its burden of proof to show that the project is necessary for the service, accommodation, convenience, or safety of the public under PURA § 37.056.

11. SWEPCO is not entitled to approval of the application.

IV. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The Commission denies the application, as outlined in this Order.

2. All other motions and any other requests for general or specific relief, if not expressly granted herein, are denied.

Signed at Austin, Texas the 13th day of August 2018.

PUBLIC UTILITY COMMISSION OF TEXAS

DeAnn T. Walker

DEANN T. WALKER, CHAIRMAN

ARTHUR C. D'ANDREA, COMMISSIONER

SHELLY BOTKIN, COMMISSIONER

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EA-2019-0010

THE EMPIRE DISTRICT
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