Southern Renewable Energy Association

P.O. Box 14858, Haltom City, TX 76117

EASTERN KENTUCKY POWER COOPERATIVE ("EKPC")

2019 INTEGRATED RESOURCE PLAN

DOCKET #2019-00096

COMMENTS OF THE SOUTHERN RENEWABLE ENERGY ASSOCIATION

June 8, 2020

The Southern Renewable Energy Association (SREA) is an industry-led initiative that promotes the use and development of renewable energy in the south. Since 2013, SREA has engaged in integrated resource plan (IRP) processes in Arkansas, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, Tennessee and Virginia. We strive to provide the most up-to-date publicly available market information regarding renewable energy resource availability, pricing, performance and forecasting. SREA appreciates the opportunity to comment on the Eastern Kentucky Power Cooperative 2019 IRP.

	Type	Megawatts
Cooper Station	Coal	341
Spurlock Station	Coal	1,346
Smith Station	Gas	989
Bluegrass Station	Gas	567
Landfill Gas	Gas	16.1
Solar	Solar	8.5
SPA	Hydro	100
Total		3,367.6

Source: EKPC 2019 IRP

In February 2015, EKPC achieved an all-time peak of 3,507 MW and expects to be in short supply of winter capacity by the year 2024. EKPC states that, "In the 2024 time frame, EKPC will either need to enter into a PPA going forward or pursue other economic power supply alternatives to be identified in an RFP process." EKPC anticipates very little change over the next few years based on its IRP results, stating "EKPC's existing resource portfolio adequately meets its power supply requirements for the next five years." EKPC compared its 2015 IRP results to this 2019 IRP. This current IRP shows that zero renewable energy resources would be acquired over the next twenty years, a departure from the 2015 IRP (Table 1-4 EKPC Projected Major Capacity Additions, page 20).

Review of EKPC's Renewable Energy Assumptions

EKPC does not publish its renewable energy cost assumptions publicly and heavily redacts many of its inputs. However, LGE&KU does publish its cost assumptions. SREA requests that EKPC file its model assumptions publicly, similar to what LGE&KU does. SREA filed comments on LGE&KU's IRP. To the extent that EKPC's data are comparable to LGE&KU, our comments remain salient. SREA found that LGE&KU's renewable cost assumptions were significantly higher than current market offerings. Given that EKPC's cost assumptions are based on data from 2016, the company's renewable energy cost assumptions are assuredly too high. Generally, renewable energy resources are available to all Kentucky utilities at roughly $30-$35/MWh, or potentially below those prices. To the extent that EKPC's renewable energy LCOE's cost assumptions deviate from $30-$35/MWh, the company is over-estimating the cost of renewable energy resources. Overestimating renewable energy cost assumptions in IRP modeling negatively impacts model selection of low-cost resources. For example, if existing fossil units operate at over $40/MWh, but renewable energy resources are assumed to cost $50-$60/MWh or higher, the model will run the fossil units and not select lower cost renewables as replacements. However, if renewable energy resources are accurately modeled, those renewable resources will offset higher cost resources and result in overall lower total system costs.

Table 8-2

Resource	Capacity Type	Capacity (MW)	Primary Fuel	Projected Capital Cost (2016$)*	
				$/kW	$M
LMS100 CT	Peaking	100	Natural Gas	[redacted]	[redacted]
Combined Cycle	Peaking/Intermediate	300	Natural Gas	[redacted]	[redacted]
Solar	Renewable	100	Solar	[redacted]	[redacted]
Wind	Renewable	100	Wind	[redacted]	[redacted]
Wind	Renewable	100	Wind	[redacted]	[redacted]
PPA - Winter Seasonal Market	Power Purchase	100	n/a	[redacted]	[redacted]
PPA - Winter Seasonal Market	Power Purchase	100	n/a	[redacted]	[redacted]
PPA - Winter Seasonal Market	Power Purchase	100	n/a	[redacted]	[redacted]

Source: EKPC 2019 IRP

NREL's ATB data is industry standard and reflects recent market offerings for renewable energy resources. For example, NREL's 2019 ATB (published in August 2019) shows wind energy resources for a levelized cost of energy (LCOE) of $30-$35/MWh, and utility-scale solar resources for a similar price.[1] These values do not include the federal production tax credit (PTC) for wind energy, nor the federal investment tax credit (ITC) for solar energy, which would decrease these costs further. It does not appear that EKPC considered federal tax credit cost reductions for renewable energy resources.

SREA recommends benchmarking IRP model LCOE's for renewable energy resources against given LCOE's from NREL's ATB as well as publicly available data from requests for proposals (RFPs) or actual power purchase agreement (PPA) contracts. By comparing IRP model LCOEs against external values, internalized variables can be pin-pointed as artificially increasing cost estimates. For example, in other IRP proceedings, SREA has found that a utility's internal cost assumptions regarding asset ownership can drastically increase the costs of renewable energy resources. Internal utility assumptions regarding self-ownership of new renewable energy generation assets tends to double-count financing costs. These are problems inherent in model assumptions that are unknowable without comparison with LCOEs, and without direct comparison of all variables included in model making. For renewable energy resources, LCOE's provide good benchmark comparisons for potential real-world PPAs, and virtually all utilities SREA has interacted with report some level of LCOE's in IRP processes.

Xcel Energy RFP Results

Xcel Energy, a Colorado electric utility, published the results of its 2017 All-Source Solicitation request for proposals in December 2017.[2] Xcel received over 400 bids representing over 100,000 MW of capacity from a wide variety of technologies; however, most bids provided wind energy or solar power resources. The median bid price or equivalent for stand-alone wind energy resources was $18.10/MWh, suggesting several projects below and above that price. Adding battery storage to wind energy resulted in median bids of $21/MWh. For stand-alone solar energy resources, the median bid was $29.50/MWh. Adding battery storage to solar energy resulted in median prices of $36/MWh. While these prices may be specific to Xcel, the fact remains that these represent real project bids and are aligned with other projections and these comments. Again, because Xcel evaluated PPAs, the values presented below are in $/MWh format, which is similar to an LCOE figure. EKPC should publish LCOE values for its generation technology assumptions to make it easier to compare the real-world PPAs against its assumed resource costs.

Xcel RFP Responses by Technology 2017

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Source: Xcel Energy 2017[3]

NIPSCO RFP Results

Northern Indiana Public Service Company (NIPSCO), an electric company in the MISO system, held an integrated resource plan (IRP) meeting on July 24, 2018 to discuss renewable energy options. As part of its IRP process, NIPSCO shared results from an all source request for proposals (RFP) summary. NIPSCO received bids for wind energy, solar energy, energy storage, and amalgamations of those resources together. The company received proposals across five states, predominately via power purchase agreement (PPA), but also as asset sale or option. Resources offered as asset sale or as an option were provided at an average bid cost of $1,151.01/kW for solar energy projects, and $1,457.07/kW for wind energy projects. For PPAs, average bids for solar energy reached $35.67/MWh, and average bids for wind energy reached $26.97/MWh. Solar-plus-energy storage projects were offered as asset sales at $1,182.79/kW and as a PPA at $5.90/kW-Mo plus

$35/MWh.[4] These values provide recent market data that are relevant to states in MISO and further south. Subsequently, NIPSCO's IRP recommended[5]:

- By 2023, the IRP preferred plan calls for adding approximately 1,150 MW of solar and solar+ storage, 160 MW of wind, 125 MW of DSM and 50 MW of market purchases to the NIPSCO supply portfolio
- Retire all NIPSCO's coal capacity by the end of 2028

NIPSCO RFP Responses by Technology 2018

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

Source: NIPSCO 2018[6]

SWEPCO's IRP Assumptions

The Southwestern Electric Power Company (SWEPCO), with customers in Arkansas, Louisiana, and Texas, recently completed its IRP in Arkansas.[7] SWEPCO modeled wind energy resources, stating "The resource had a LCOE of $21.85/MWh in 2021 with an 80% PTC, without congestion and losses. The levelized congestion and losses for the 2021 wind resource is estimated to be approximately $6/MWh." SWEPCO also modeled utility-scale solar, stating "Initial costs for Tier 1 were approximately $1,180/kW in 2021 with the ITC. Tier 2 has an initial cost of approximately $1,310/kW in 2021 with the ITC."

SWEPCO's Preferred Portfolio:

- "Adds utility-scale solar resources in 2025 through 2032, for a total of 1,300MW (nameplate) of utility-scale solar by the end of the planning period."
- "Adds 600MW (nameplate) of wind resources in 2022 and 2023 and 200MW (nameplate) in 2024, with additional wind resources added through 2029, for a total of 2,000MW (nameplate) by the end of the planning period."

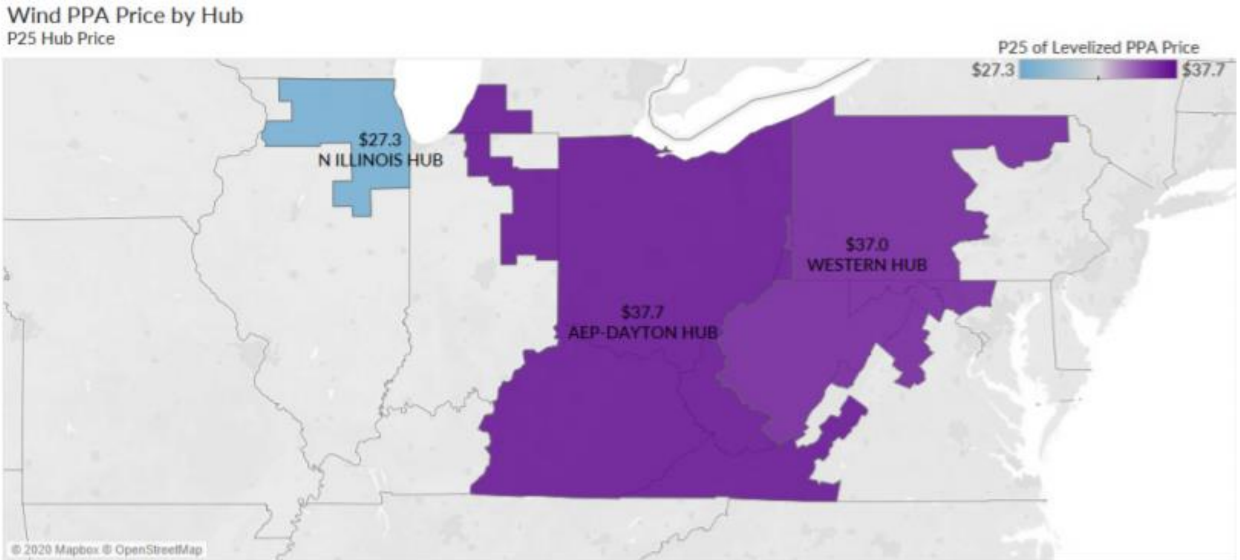
Cleco's IRP Data Assumptions

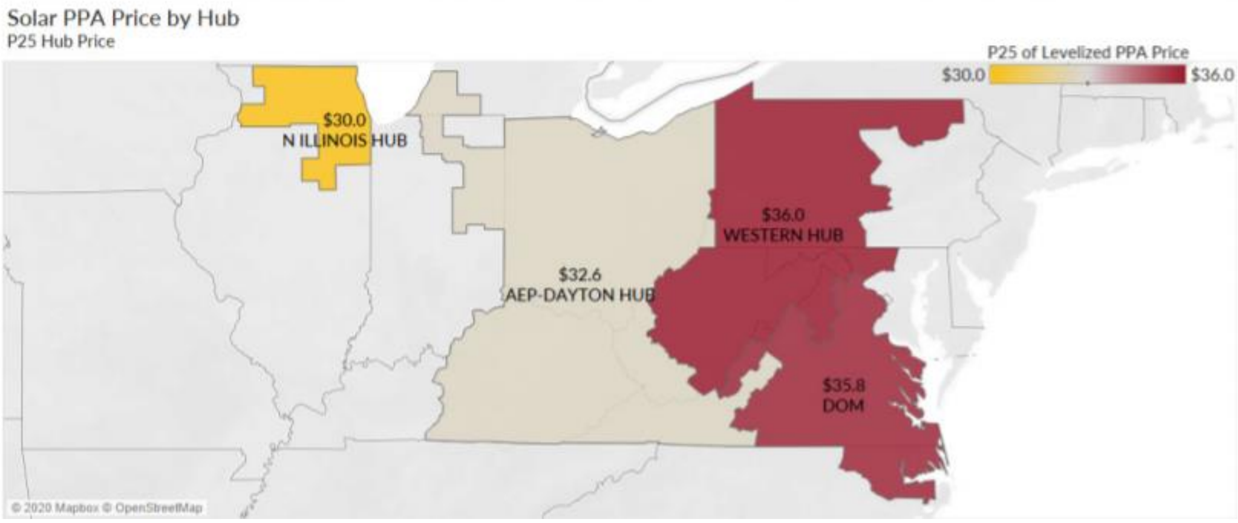
Cleco Power LLC, an electric utility in Louisiana, recently published its Draft IRP. Cleco found that "The preferred portfolio includes acquiring up to 400 MW of installed solar capacity, as well as up to 1,000 MW of installed wind capacity."

- Cleco evaluated wind energy with a PPA. Cleco states, “The wind PPA assumed a fixed price of $20/Mwh over the term of the study with an additional $7/MWh adder for potential firm transmission costs, whether incurred by congestion costs between MISO North and South or for wheeling out of SPP. Due to the increased prevalence and strength of wind as a resource in certain geographic areas in TRG 1 areas relative to MISO South, a higher capacity factor of 48%-53% will be used for the wind PPA.” These prices are in line with SWEPCO’s IRP, NIPSCO’s RFP and NREL’s ATB.
- Cleco also evaluated solar energy with a PPA. Cleco states, “The solar PPA will use a fixed price of $35/MWh over the term of the study. Since it is assumed to be in MISO South, no transmission adder or capacity factor adjustment will be made relative to the self-build option.” These prices are in line with SWEPCO’s IRP, NIPSCO’s RFP and NREL’s ATB.

Additional Utility Benchmarks

Several other publicly available data points exist for recent renewable energy PPAs. For example, the Georgia Power 2019 IRP has stated that the company’s average solar power purchase agreement reached $36/MWh in 2017.[8] In North Carolina, competitive procurement of solar energy resources recently led to an average price of $31.24/MWh per proposal.[9] In Lafayette, Lafayette Utilities System (LUS) recent wind energy PPA for 50 megawatts (MW) is currently providing energy for $31.86/MWh and is providing nearly 20% of Lafayette’s energy.[10] LevelTen Energy, and independent aggregator of renewable energy buyers and sellers, releases quarterly information regarding renewable energy PPA's by region. Recent wind energy PPA prices in the PJM AEP-Dayton Hub area are near $37.7/MWh and solar energy PPA prices are approximately $32.6/MWh.[11]





Source: LevelTen 2020[12]

In 2018, SREA filed comments in the Big Rivers Energy Cooperative ("BREC") IRP docket (#2017-00384). BREC's IRP found no need for renewable energy resources in the near-term, but the IRP contained significant deficiencies that hamper renewable energy review. On May 27, 2020, BREC announced two new solar PPA's for up to 260 MW's.[13] Additionally, Owensboro Municipal Utilities (OMU) and Kentucky Municipal Energy Agency (KyMEA) recently announced an 86-megawatt solar power purchase agreement, and that project will use single-axis tracking.[14] Given the increased interest in renewable energy resources by Kentucky utilities, EKPC's lack of any renewable energy development in its most recent IRP strongly suggests improvements need to be made to the report.

Federal Tax Credits Were Not Properly Evaluated

The federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) are the primary incentives for the wind energy industry and solar energy industry, respectively. Because of congressional action in 2015, the PTC and ITC are being phased out, even while federal incentives for conventional forms of generation remain in place. The information provided below is meant to provide additional clarity regarding the PTC and ITC and generally how these incentives should be considered for modeling purposes. It is not apparent that EKPC's IRP even includes the PTC or ITC.

Production Tax Credit

Wind energy developers can qualify projects for specific PTC rates by commencing construction in a particular year and bringing such projects online within four calendar years. For example, a wind energy project that commences construction by the end of 2016 has until the end of 2021 to begin operation, and still qualify for the full PTC. Projects that begin construction in 2017 have until the end of 2022 to become operational and qualify for a 20% reduced PTC value; 2018 projects can come online by 2022 and 2019 projects by 2023 with further 20% annual reductions in PTC value. Renewable energy project developers frequently safe-harbor qualified clean energy equipment in anticipation of a future contract and reflect cost reductions in the proposals. These safe harbor provisions have been extended due to recent action by the IRS due to delays caused by coronavirus.[15]

The PTC is awarded on a generation basis at a rate of $24/MWh for the first ten years of a project's operation. Because the PTC is a tax credit and it frequently exceeds a project developer's total tax base, developers will frequently monetize the PTC with tax equity. Tax equity erodes the full dollar value of the PTC. According to the Lawrence Berkeley National Lab (LBNL), for a developer with tax appetite, the 100% PTC value is reduced to $19.8/MWh.[16] According to LBNL, developers should expect a $15-$19/MWh reduction in overall cost of energy from the PTC. To achieve an equivalent PTC cost reduction, it is recommended that wind energy resources' overnight capital costs be reduced by roughly $600/kW for resources that become operational in 2021 (reflecting 100% of the PTC value), $500/kW for wind resources operational in 2022 (80% of PTC value), and $400/kW for wind resources operational in 2023 (60% of PTC value). Due to a last-minute Congressional extension of the wind energy PTC, the 60% PTC value has been extended by an additional year.

Schedule of Wind PTC Cost Reductions by Project In-Service Dates

	2020	2021	2022	2023	Future
Wind PTC	$19.8/MWh	$19.8/MWh	$16.9/MWh	$14.2/MWh	0
OR Wind PTC (Overnight $/kW translated)	*$600/kW*	*$600/kW*	*$500/kW*	*$400/kW*	*0*

Source: Adaptation from LBNL 2014[17]

Investment Tax Credit

Rules for the solar ITC are slightly different compared to the wind PTC. Based on IRS Notice 2018-59, "As modified, § 48 phases down the ITC [from 30%] for solar energy property the construction of which begins after December 31, 2019, and before January 1, 2022, and further limits the amount of the § 48 credit available for solar energy property that is not placed in service before January 1, 2024." In effect, the ITC phase-out for solar ends for projects that commence construction in 2019, 2020 or 2021 by January 1, 2024. For solar projects that begin construction on or after January 1, 2022, a permanent 10% ITC is available.[18]

Most utility-scale solar energy projects will elect to receive the ITC, which is based on total project expenditure. It is recommended that the full 30% ITC be incorporated for projects that begin operation before 2024, and a 10% ITC be incorporated for projects that begin operation in 2024 and future years. Additionally, new energy storage projects can also qualify for the ITC, provided that those projects are added to new or existing wind energy or solar energy projects. Currently, stand-alone energy storage projects do not qualify for the federal ITC.[19]

Schedule of Solar ITC Cost Reductions by Project In-Service Dates

Construction Begins	2020 Operational	2021 Operational	2022 Operational	2023 Operational	Future Op.
Before 2020	30%	30%	30%	30%	10%
2020	26%	26%	26%	26%	10%
2021		22%	22%	22%	10%
2022 and Future			10%	10%	10%

Source: Adaptation from IRS 2018[20]

Capacity Planning is Deficient

SREA's concern with capacity-based planning is that that even if renewable energy cost assumptions were below avoided cost, a utility's modeling methodology would refuse to select low-cost renewable energy, regardless of price. This has been proven true with other IRPs. Capacity-only planning leads to a Catch-22 for renewable energy resources. In instances where capacity needs are satisfactorily met under the status quo, a model will not select new low-cost energy resources and instead rely on higher cost capacity resources for energy delivery. However, when a capacity-based model is provided a capacity need (either through extensive retirements or significant load growth), renewable energy resources are only evaluated on their capacity value, not their low-cost energy contributions. Capacity-only planning leads to over-building of new natural gas power plants, when a mixture of low-cost renewable energy resources would likely lead to overall reduced ratepayer costs. To be clear, this is not an argument that all existing capacity resources should be retired. In normal dispatch operations, higher cost generation resources would be ramped down to accommodate lower cost renewable energy resources when available. Lower-cost energy-based resources reduce overall total costs; however, capacity-only planning does not take the normal dispatch operations into consideration. This is an unfair standard that always leads to devaluing renewable energy resources, while always building rate-based new natural gas power generation.

Synapse Energy Economics has noted the deficiency of capacity expansion models, stating:

> "In addition, some capacity expansion models are unable to endogenously retire EGUs, and require these decisions to be made outside of the model construct. While making decisions outside the model reduces computational requirements, it may introduce user error or bias. For example, a modeler may not review economic retirements, and thus fail to capture a cost-effective compliance mechanism."[21]

According to Moody's Investors Service, "Some coal plants still perform economically, but competitiveness could come under pressure as market conditions evolve...Most municipal- or G&T-owned coal plants in the US are old and have high production costs. According to the report, 72.3% of these plants, or about 65.0 gigawatts, have operating costs exceeding $30 per megawatt hour, which Moody's views as the threshold above which coal plants are vulnerable to be displaced by cheaper generation options. Newer units that came online after 2000 use more efficient technology and run at lower heat rates and operating costs, enabling many of them to be competitive with the market and achieve higher capacity factors. Others are located adjacent to coal mines, allowing them to eliminate transportation costs from their overall fuel expenses. Nonetheless, each plant's competitiveness will ultimately depend on external factors including the price of natural gas and renewable energy in the vicinity, regional transmission organization reserve margins and the extent of political support for various fuels."[22] As Moody's points out, broader energy market forces will render higher cost energy resources (such as existing steam turbine generation) obsolete and likely to be out-competed by lower cost energy resources such as renewable resources.

If EKPC relies on power that costs $35/MWh or more, at that price, both wind energy and solar energy resources are available at lower prices and should have been selected in a truly integrated resource plan. EKPC's selection of only market-based capacity options suggests that renewable energy resources were not appropriately modeled.

Over-reliance on capacity-focused modeling underestimates renewable energy benefits while retaining older, less efficient generation. Taken to the extreme, a capacity-only planning process could lead to unusual model results that recommend significant power generation development or legacy generation retention that are rarely used, at the expense of low-cost energy options. This outcome appears to have occurred, given that low-cost wind energy and solar energy generation were not selected in the next few years. Capacity-focused planning does not initially address economic costs; alternatively, an energy-based financial dispatch model would efficiently dispatch necessary resources. EKPC should evaluate energy planning options, not just capacity. EKPC even noted that it "…continues to need to hedge its energy price exposure throughout the entire year." However, the current modeling practices to not adequately capture hedging opportunities, and thus EKPC ratepayers are likely over-paying for energy resources compared to current renewable energy offers.

Further, EKPC did not provide a compelling explanation for the cost assumptions used for its "PPA Market Power Purchase" options. Those PPA's were the only resources selected in EKPC's modeling. If EKPC is presuming that short-term capacity prices in PJM are to remain relatively low for the next thirty years, the company needs to provide a compelling narrative to explain such a view.

Expand Collaborative 2.0 Membership

EKPC provided information regarding its Collaborative 2.0 stakeholder outreach efforts. SREA commends EKPC at this voluntary effort and we encourage the company to expand the membership to include utility-scale renewable energy development interests.

Issue a Renewable Energy RFP

SREA understands that EKPC relies on the NRCO for renewable energy requests for proposals (RFP). However, given EKPC's outdated renewable energy cost assumptions, no recent information from NRCO has been used in this IRP's model assumptions and inputs. SREA recommends that EKPC incorporate data from NRCO in future IRPs, and to immediately issue a renewable energy RFP to appropriately gauge current market offerings. Because EKPC is under no obligation to take resources bid into an RFP, issuing an RFP is a zero-regret action that could verify IRP results or identify new opportunities.

EKPC IRP Recommendations

- EKPC should move away from capacity-only or capacity-focused resource planning.
- EKPC should allow renewable energy to directly compete against existing generation units.
- The National Renewable Energy Lab's Annual Technology Baseline should be used for all renewable energy resource cost and performance assumptions.
- Energy storage resources should be allowed to access multiple revenue streams including but not limited to frequency control, voltage regulation, energy arbitrage, peaking and other value stacks.
- Cost projections for renewable energy and energy storage should continually decline over time, while performance projections should continually increase.
- Federal tax credits, including the PTC and ITC, should be incorporated for renewable energy and energy storage projects in relevant years, as provided in these comments.
- Levelized cost of energy benchmarks (in $/MWh values) should be provided for all energy resources. LCOE values should be like Lazard Associates' and NREL ATB values.
- Significant procurement of renewable energy and energy storage should occur across all portfolios.
- Large customers should be allowed to directly procure renewable energy resources.
- Incorporate data from NRCO renewable energy RFP's into IRP planning.
- Issue an RFP for renewable energy resources to gather updated market information.
- Expand the Collaborative 2.0 membership to include utility-scale renewable energy development.

CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of the foregoing is a true and accurate copy of the document(s) being filed in paper medium; that the electronic filing was transmitted to the Commission on June 8, 2020 that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding. All parties of record have been provided with these comments electronically.

Simon Mahan
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Southern Renewable Energy Association

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