Southern Renewable Energy Association
P.O. Box 14858, Haltom City, TX 76117

July 23, 2019

Ms. Terri Lemoine Bordelon
Records Section
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North Fifth Street
Baton Rouge, LA 70802

RE: LPSC Docket No. I-34694. ***Integrated Resource Planning ("IRP") Process for Entergy Louisiana LLC ("ELL") Pursuant to General Order Dated April 20, 2012***

Dear Ms. Bordelon,

Please find an original and four copies of this letter by the Southern Renewable Energy Association (SREA) regarding LPSC Docket No. I-34694 in Re: 2017 Integrated Resource Planning ("IRP") Process pursuant to General Order No. R-30021, Dated April 20, 2012.

Sincerely,

Simon Mahan
SREA Executive Director

CERTIFICATE OF SERVICE

I hereby certify that I have this 23rd day of July, 2018 served copies of the foregoing pleading upon all other known parties of this proceeding, by email.

Simon Mahan

Dear Commissioners and Staff,

The Southern Renewable Energy Association (SREA) is an industry-led initiative that promotes responsible use and development of wind energy, solar energy, energy storage and transmission solutions in the South. We appreciate the opportunity to provide comments on Entergy Louisiana, LLC'S Final 2019 Integrated Resource Plan (IRP). As contrasted to the collaborative stakeholder processes with Cleco's and Southwestern Electric Power Company's (SWEPCO) IRP's, ELL's IRP is noncompliant with the Louisiana Public Service Commission's (LPSC's) IRP rules, and has been contrary to best planning practices. As such, ELL's IRP poses significant risks to Louisiana ratepayers. SREA recommends that this Final IRP be rejected by the Commission.

The LPSC's IRP rules state that, "The overall objective of the IRP Process is to evaluate a comprehensive set of potential resource options, including supply-side, demand-side and economic transmission resource options, to determine a base or 'reference resource' plan that offers the most economic and reliable combination of resources satisfying the forecasted load requirements." ELL did not evaluate multiple configurations of renewable energy resources, such as importing renewable energy, Power Purchase Agreement (PPA) style contractual options, and multiple configurations for energy storage; thus, ELL did not "evaluate a comprehensive set of potential resource options". ELL did not conduct an analysis to evaluate "economic transmission resource options" or potential upgrades to access low-cost renewable energy resources. ELL's reliance on capacity-only planning may qualify as conducting *reliability* planning, but it does not inherently qualify as economic and energy planning.

SREA's comments in this IRP process have focused on capacity-only planning deficiencies, as well as problems with renewable energy assumptions. Capacity-only planning does not adequately evaluate possibly lower-cost energy options that would reduce ratepayer costs. ELL's renewable energy assumptions over-estimate the cost of renewable energy resources, and artificially constrain renewable energy options. Our comments and recommendations have not been adopted in any meaningful way by Entergy.

ELL rejected stakeholder concerns that its IRP models overly-relies on capacity-based planning. ELL's response to SREA's comments verified our concerns: "As has been previously stated, the Capacity Expansion optimization component of ELL's IRP seeks to add resources (either supply-side or demand-side) only when there is a projected capacity deficit. Given that a deficit is not projected within the next five years, no new resources have been identified within that period. That said, ELL recognizes the variety of benefits that renewable resources can provide its customers and, as seen in ELL's Action Plan, will seek to issue renewable RFPs within the next five years." While the rest of the country's electric utility industry is moving forward on renewable energy resources, ELL's process led to a result where the company planned to "do nothing" for the next five years. ELL's model results for this IRP are contrary to Entergy's own corporate statements regarding large renewable energy procurement plans and corporate sustainability goals; Entergy's plans provided to the Midcontinent Independent System Operator; and, Entergy's model results are not reflective of the electric utility industry at-large.

This is not solely an ELL problem. ELL's resource planning is mostly conducted by Entergy's corporate resource planning group, and SREA has witnessed similar problems in other

Entergy jurisdictions. Because Entergy's system-wide IRP process is so deficient, the company conducts its renewable energy procurement strategy almost entirely outside of IRP parameters.

Disputed Item #1: Capacity-Only Planning is Deficient

SREA has been involved with reviewing other Entergy IRP's in Arkansas (EAI), Mississippi (EMI) and New Orleans (ENO), as well as the 2015 ELL IRP. Across the Entergy footprint, the company relies on capacity-only planning. Due to our extensive working knowledge of Entergy's resource planning practices, SREA notes that Entergy's capacity-based planning practices undervalue near-term, low-cost renewable energy resources. Beginning with our June 14, 2018 comments regarding ELL's proposed data inputs, we provided this stark example:

> "Entergy Arkansas Incorporated (EAI) and ELL both use very similar (or, the same) methodology, data inputs and software for IRP processes…. EAI's preliminary results across all three scenarios show that the AURORA model acquires no new generation until 2025, when the company experiences a capacity shortfall. In effect, the AURORA model runs do not procure lowest-cost energy resources if no capacity need is identified, and artificially retain existing units despite lower-cost option availability. When asked if the model would select a hypothetical zero-dollar ($0/MWh) resource, when no capacity was needed, the response from EAI was that the company would seek out those types of resources even if the IRP or model does not select them – again suggesting the current modeling software does not prioritize low-cost resources…. ELL should evaluate low-cost energy purchases in its modeling, even if no capacity need exists."

SREA's concern in June 2018 was that even if renewable energy cost assumptions were below avoided cost, Entergy's modeling methodology would refuse to select low-cost renewable energy, regardless of price. Our concern was validated in EAI's process, as that company's models showed no capacity need, and no renewable energy procurement until 2025. That same faulty EAI software and methodology are the same software and same methodology used by ELL. SREA's concern has also materialized in ELL's current IRP. ELL's results, that no capacity need exists until the mid-2020s, and therefore, no new power generation was selected in its IRP, is virtually the same result as EAI. ELL has never adequately responded to this problem.

Even though Entergy's IRP results in Arkansas showed no new generation until 2025, Entergy staff hinted that EAI planned to ignore the IRP results and procure renewable energy anyway. Shortly after EAI filed its IRP in Arkansas, the company issued a 200 MW RFP for solar power.[1] Again, similar to EAI, ELL staff have noted that even though the IRP model results do not select renewable energy, Entergy plans to ignore its IRP results and will issue a renewable energy RFP soon.

Capacity-only planning, as conducted system-wide by Entergy, leads to a Catch-22 scenario for low-cost energy resources. In the 2015 IRP, ELL stated that because renewable energy resources "are not economically attractive relative to conventional gas turbine technology (whether in simple or combined cycle) as solely a capacity resource", ELL's model results led to substantial new build of natural gas generation resources. In the 2015 IRP, no renewable energy resources were selected for ELL and only gas units were selected. Instead of resolving overwhelming deficiencies in the final ELL 2015 IRP, the company voluntarily agreed to issue a 200 MW RFP for renewable energy resources.

In 2015, ELL stated renewables do not provide enough capacity thus no renewables would be purchased but in 2019 ELL is now saying that because no new capacity is needed, no renewables would be selected. This is an unfair standard that always leads to devaluing renewable energy resources, while always building rate-based new natural gas power generation.

SREA's position has been, and continues to be, that if Entergy were to accurately model renewable energy resources, the IRP would help inform timing, quantity, and type of new generation technologies to be procured. ELL's current IRP process appears to be: ignore IRP rules, reject stakeholder feedback, disregard the resulting model runs, and issue a renewable energy RFP to pacify stakeholder concerns. This is an unsustainable IRP process and in no way protects the Louisiana ratepayers.

ELL's Current Fleet and Energy Procurement Are Higher Cost than Renewable Energy

SREA provided *Entergy's Statistical Report and Investor Guide Unit Data* for 2016 and 2017; data that ELL should have provided in this IRP. We will also provide the updated 2018 data, published in June 2019, as Appendix A and Appendix B. The self-reported data from Entergy shows that the company owns, operates, or purchases a substantial amount of energy at over $35 per megawatt hour ($35/MWh). 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. SREA has provided substantial quantities of data from other electric utilities, government agencies and consulting firms to substantiate our credible comments. All those data reinforce SREA's position that renewable energy resources are available, today, for under $35/MWh, which is lower-cost than a significant amount of energy procured by Entergy.

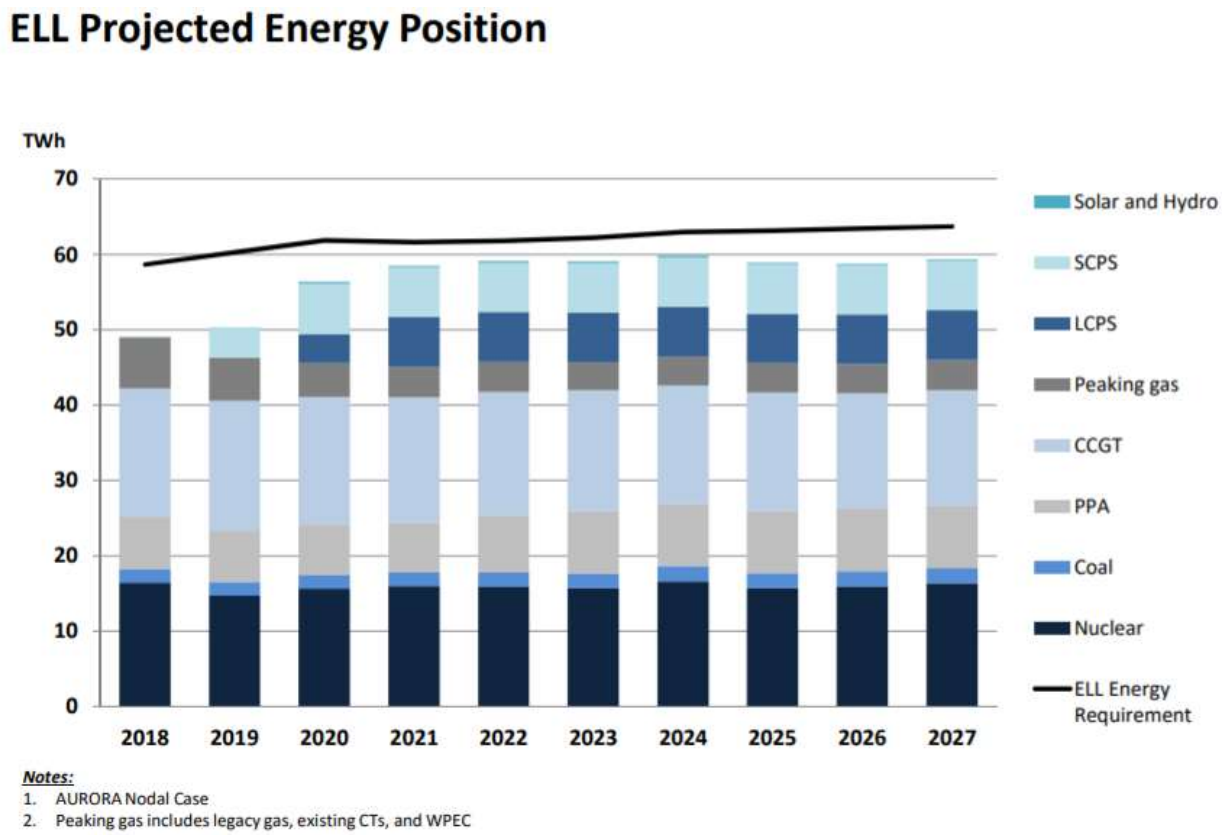
Entergy System Energy Purchases and Fuel-Only Costs

	Natural Gas		Nuclear		Coal		Purchased Power		MISO Purchases	
Year	% of Gen	Cents Per kWh	% of Gen	Cents Per kWh	% of Gen	Cents Per kWh	% of Gen	Cents Per kWh	% of Gen	Cents Per kWh
2018	39	2.84	27	0.84	9	2.24	8	5.23	17	3.71
2017	38	2.60	26	0.86	8	2.35	8	4.02	20	3.09
2016	41	2.44	28	0.63	7	2.65	9	3.71	15	3.13

	Natural Gas		Nuclear		Coal		Purchased Power (d)		MISO Purchases (e)	
	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019
Entergy Arkansas (a)	29%	31%	47%	53%	20%	15%	—	1%	4%	—
Entergy Louisiana	39%	53%	29%	28%	3%	4%	9%	15%	20%	—
Entergy Mississippi (b)	48%	56%	16%	31%	16%	13%	—	—	20%	—
Entergy New Orleans (b)	52%	53%	33%	44%	2%	2%	1%	1%	12%	—
Entergy Texas	34%	31%	9%	16%	6%	10%	29%	43%	22%	—
System Energy (c)	—	—	100%	100%	—	—	—	—	—	—
Utility (a) (b)	39%	45%	27%	35%	9%	9%	8%	11%	17%	—

Source: Entergy 2019[2]

Lower cost energy resources, like wind energy and solar power, will not be selected in ELL's AURORA modeling runs until ELL inputs a capacity need. In effect, ELL is spending more to procure higher cost energy through the MISO market, than what it would if the company were to procure renewable energy resources, and will continue to do so for the next decade. Some 20% of ELL's energy was purchased through MISO in 2018 at a cost of approximately $37.10/MWh. An additional 9% of ELL's energy was procured potentially at a cost of $52.30/MWh.[3] ELL projects an energy need in its Final IRP. Because Entergy is the largest provider of energy in the MISO South market, it is entirely possible that ELL customers are procuring energy resources from other Entergy subsidiaries, subsidizing those systems.



Source: Entergy 2018[4]

One way to measure the cost differential would be for ELL to select a few of its highest cost units and build into the model an assumption that those units are no longer available and no longer have any cost to the system.[1] Once the model is *allowed* to build capacity, it will select the lowest cost new generation resources. ELL would then compare the different individual retirement scenarios on a $/MWh basis or overall PVRR: no new capacity build and maintaining existing resources versus new generation procurement. This is a similar procedure followed by Cleco in its IRP and its results corroborate SREA's recommendations.

Problems with AURORA Planning Software Remain Unresolved

In June 2018, SREA recommended that ELL develop a study should develop a study detailing the various benefits and limitations of its current modeling software. In 2017, Puget Sound Energy (an electric utility in Washington state), conducted a brief overview of AURORA versus Plexos software, highlighting the benefits of using the Plexos software.[5] AURORA

[1] Such as Little Gypsy (929 MW at $48.70/MWh), Waterford (872 MW at $45.20/MWh), Calcasieu (303 MW at $68.30/MWh) or Big Cajun II (140 MW at $38.80/MWh). All unit data are available from Entergy. ELL has already evaluated several of its existing units for possible retirement. In Docket No. U-34472 regarding the Washington Parish Energy Center, the LPSC Order states, "ELL represents that, based on current forecasts, assumptions, and transmission plans, and the additions of St. Charles Power Station and WPEC, one of the following legacy gas—fired generation units could be deactivated or retired without need for alternative reliability mitigation measures: Little Gypsy 2, Little Gypsy 3, Waterford l, or Waterford 2."

appears to be a capacity-centric modeling product, whereas Plexos appears to have greater flexibility in evaluating lowest cost energy resources, capacity resources and sub-hourly ancillary services. Based on analysis by Puget Sound Energy, the AURORA suite of products focuses on hourly capacity-based operations; however, Plexos can provide sub-hourly operational capabilities. ELL responded to SREA's comment by stating that the company has used AURORA since 2013 and has found no need to change.

In January 2019, SREA provided additional information regarding AURORA. In 2014 Wärtsilä, a leading provider of flexible power generation solutions including energy storage, conducted an analysis of future resource planning needs. Wärtsilä found that, "Capacity Expansion Models (CEMs) are generally found in software packages such as Ventyx Strategist (PROVIEW)™, ***EPIS AuroraXMP™,*** SDDP OptGen™, and others. These packages make use of something called the Load Duration Curve (LDC), a mathematical simplification that makes the computational burden of obtaining solutions tractable...With aggressive penetration of renewable energy, which has accelerated rapidly in the last decade, ***it is questionable whether the traditional LDC simplification is still valid***. To address this potential problem, new software packages, such as [Energy Exemplar's] ***Plexos™*** are available that use what is called Chronological modeling."[6] (emphasis added) MISO relies on Plexos, as does the Southwestern Electric Power Company (SWEPCO), in modeling practices.

In 2018, Energy Exemplar (the developer of Plexos) purchased EPIS and its Aurora software. Currently, the Southwestern Power Pool (SPP) Regional Transmission Organization is evaluating new software programs for its planning purposes. SPP is only considering ABB's PROMOD product and Energy Exemplar's Plexos product. Energy Exemplar has not encouraged using the Aurora product to SPP, suggesting the deficiency in that software relative to their other products. On July 11, 2019, Energy Exemplar hosted a webinar regarding transmission expansion planning with its software program, Plexos. Energy Exemplar staff did not recommend using AURORA on its webinar.

SREA has spoken with other regulatory staff, other utilities, other stakeholders involved with AURORA in other states, and even Energy Exemplar representatives regarding the AURORA software. The deficiencies of AURORA are well-known. Even ELL has noted deficiencies with AURORA. ELL stated that part of the reason why it did not do transmission expansion planning in this IRP, as required by the LPSC IRP rules, is that it would be difficult with all the data requirements and modeling runs. Similarly, ELL stated that it would be difficult to conduct retirement analyses in the IRP, despite having nearly a three-year window for running models and collecting data. Also, SREA has recommended conducting sub-hourly planning sensitivities regarding energy storage, but again ELL has stated this is too difficult. Finally, Entergy's model outputs show no need for renewable energy, yet Entergy as company policy appears to (rightfully) ignore those results and issue renewable energy RFPs anyway. AURORA cannot simultaneously be an adequate software program, while being a scapegoat for not doing proper analysis when other software programs are readily available and used by other utilities.

Disputed Item #2: Renewable Energy is Not Adequately Evaluated

Even if Entergy abandons its capacity-only evaluations, and begin to accurately evaluate energy planning in an integrated way, the assumptions and methodologies used by Entergy regarding renewable energy resources are inaccurate. SREA's requests for transparency on renewable energy pricing have fallen of deaf ears. Based on SREA's involvement in the 2015 ELL IRP, we anticipated that ELL would publish data in a similar fashion to its previous IRP (see Table 1 in the 2015 IRP).[7] However, in its 2019 IRP Report, Entergy has essentially abandoned the progress towards transparency achieved four years ago. SREA has noted a number of deficiencies in Entergy's renewable energy assumptions; however, none of our requests for assumption substitution have been fulfilled. As such, Entergy is missing opportunities to procure low-cost renewable energy resources and help keep ratepayer costs in check.

Cost Assumptions are Too High

Regarding renewable energy cost assumptions, ELL stated that "Cost projections included in the modeling and documented in the assumptions filing reflect current industry understanding and expectations. These have also been benchmarked against market data from RFPs and/or unsolicited offers." SREA, as a renewable energy trade association, can verify that ELL's cost projects do not reflect "current industry understanding". As our comments to the Draft IRP stated, ELL's assumptions result in renewable energy costs of nearly 30-50% higher than current market offerings. ELL did not respond to that comment in this Final IRP.

Entergy obfuscates its cost assumptions associated with new generation resources. While ELL does provide some cost assumptions, it did not provide all cost assumptions, making it difficult to identify potentially over-estimated variables, or potentially double-counted variables. For example, ELL notes that "Similarly, SREA noted at the November 27, 2018 Technical Conference that ELL had failed to provide Levelized Cost of Energy estimates for renewables. ELL responded that those estimates had been provided and were publicly available on ELL's IRP Website." The LPSC IRP rules state that the IRP *Report* should contain all relevant data, not that data should be provided piecemeal for current and future stakeholders to fit together like a puzzle.

SREA's experience in Arkansas with EAI has helped us discern renewable energy data and methodologies not reported by ELL in this IRP. This Final IRP Report contains no levelized cost of energy (LCOE) data regarding renewable energy resources, and the only cost assumptions regarding renewable energy are blacked out, and marked as confidential. ELL does not publicly provide all variables for each generation resource. For example, ELL's cost of capital methodology is not provided with regards to renewable energy. SREA discovered in the 2015 IRP that ELL was mis-applying its cost of capital to non-overnight costs of renewable energy generation, and not evaluating PPA's as alternatives, effectively double-counting cost of capital. With this Final IRP Report, it is impossible to determine if ELL double counted the cost of capital. Stakeholders should not have to be involved in six years' worth of IRPs in multiple states to hopefully glean a utility's data and methodology assumptions.

ELL responded to SREA's recommendation to benchmark cost assumptions against Lazard Associate's LCOE values. ELL published its response in its Draft IRP Report on October 12, 2018 that, "Lazard produces capital cost and LCOE/LCOS estimates for generation alternatives and storage. These are roughly consistent with ELL's internal calculations and external consultant data." However, SREA responded that Entergy's LCOE's for renewable energy are potentially 50% higher than Lazard's values, and other publicly available resources. ELL did not refute this discrepancy in this Final IRP Report, nor did it respond to this information.

ELL's newest response in this Final IRP Report is that, "ELL is unable to directly compare the capital costs provided in the referenced Lazard document to the information used within this IRP due to the lack of details provided by Lazard (e.g. are the numbers quoted in $/kW-AC or $/kW-DC, what year is the data quoted in, etc)." SREA provided significant quantities of data over a year ago, ELL has had sufficient time to ask questions of SREA, or contact Lazard directly. Even ELL's IRP does not distinguish whether their own data are listed in $/kW-AC or $/kW-DC (See Table 11 and Figure 15). ELL's October 2018 statement that its data assumptions for this IRP are "roughly consistent" with Lazard's data, and then its May 2019 response that the company is "unable to directly compare the capital costs provided in the referenced Lazard document", are contradictory. SREA's recommendation, that ELL benchmark its cost and performance data against LCOE's would capture imbedded assumptions and methodologies *not* reported by ELL and all other data sources. LCOE price comparisons provide at least some level of a universal end-case benchmark, so while individual variables (like capital cost, or capacity factor) may be slightly different, the end-results can be more fairly compared. As mentioned previously, ELL published its LCOE's for all generation technology is an easily viewable chart in the 2015 IRP, and is common practice with all other utilities, including ELL's sister companies. Despite Entergy's obfuscation of renewable energy cost data, SREA can definitively state that ELL's cost estimates for renewable energy resources are too high.

Entergy's Renewable Cost Assumptions Are Higher Than Current Renewable Procurement Data

It is highly recommended that utilities should develop a request for proposals (RFP) or request for information (RFI) in tandem with IRP development to receive the most recent market information, specific to that utility. Developing an RFP or RFI to coincide with an IRP would create a significant amount of high-quality data, while potentially expediting future power purchase agreements, procurements or developments. ELL specifically rejected this recommendation, stating the company felt its data is adequate. Additionally, SREA's recommendation that ELL should conduct financial sensitivities regarding utility-ownership versus a PPA was never addressed.

Xcel Energy RFP Results are Lower than Entergy's Data Assumptions

Xcel Energy, a Colorado electric utility, published the results of its 2017 All-Source Solicitation request for proposals in December 2017.[8] 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. Entergy 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[9]

NIPSCO RFP Results are Lower than Entergy's Data Assumptions

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 PPA's, 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.[10] These values provide recent market data that are relevant to states in MISO and further south. Subsequently, NIPSCO's

IRP recommended[11]:

- 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 of 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[12]

NIPSCO's data shows that Entergy's capital cost assumptions for wind energy and solar power are approximately 20%-30% higher than resources bid into Northern Indiana's RFP last year on a $/kW basis. A >20% higher cost associated with wind energy or solar energy resources would potentially cause the total exclusion of wind energy or solar energy resources in IRP modeling.

Additional Utility Benchmarks Show Entergy's Renewable Assumptions are Wrong

Several other publicly available data points exist for recent renewable energy PPA's. For example, the Georgia Power 2019 IRP has stated that the company's average solar power purchase agreement reached $36/MWh in 2017. [13] In North Carolina, competitive procurement of solar energy resources recently led to an average price of $31.24/MWh per proposal.[14] 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.[15]

Independent Research Proves Entergy's Cost Assumptions are Too High

The National Renewable Energy Lab (NREL) publishes its Annual Technology Baseline (ATB) as a resource for "realistic and timely set of input assumptions (e.g., technology cost, fuel costs), and a diverse set of potential futures (standard scenarios) to inform electric sector analysis in the United States. The products of this work, including assessments of current and projected technology cost and performance for both renewable and conventional electricity generation technologies, as well as market projections of more than a dozen scenarios produced with NREL's Regional Energy Deployment Systems (ReEDS) model…."[16] NREL's ATB is one of the most comprehensive, and accurate, resources for various energy resource inputs. NREL's ATB is used by regional transmission organizations (RTOs) including the Midcontinent Independent System Operator (MISO)[17] and PJM.[18] NREL's ATB data should be used for model inputs and future forecasts. Given that future purchases of renewable energy resources would take several years before power production, NREL ATB data starting in 2019 or 2020 is recommended, as well as incorporating future pricing and performance levels. NREL's ATB is updated annually, usually in July or August.

Wind Energy

NREL's ATB evaluates wind energy resources as "techno-resource groups" (TRGs) that effectively provides a scale of various wind energy opportunities.[19] For example, TRG 1 resources are anticipated to be the lowest cost and highest performance wind energy resources and are mostly concentrated in the Central US. A fair amount of wind energy capacity potential in the Southeast opens with TRG 5, with the entire Southeastern region opening with TRG 7. Based on the current market, the "low" values for NREL ATB's land-based wind resources should be used, beginning in 2019 or 2020. Evaluating these three different wind energy resources provides an adequate range of wind energy resources available to the Southeast.

Evaluating multiple types of wind energy resources, and not solely evaluating the lowest cost options (e.g., TRG 1 resources), may help identify different generation profiles that more closely align with a utility's demand load. Geographic diversity of renewable energy resources is anticipated to generally increase capacity value of a resource and reduce overall generation variability. Hourly and sub-hourly wind energy generation profiles are available from the NREL Wind Integration National Database (WIND) Toolkit for up to 122,000 different sites across the country. Data are available from NREL, here: https://www.nrel.gov/grid/wind-toolkit.html

The federal Production Tax Credit (PTC) for wind energy is expiring. The details of the PTC will be discussed later; however, for the chart below, the PTC has been converted into a rough reduction in overnight capital costs. Generally, CAPEX costs below have been reduced by $600/kW in 2019 and 2020, $500/kW in 2021, and $400/kW in 2022.

NREL ATB Wind Energy Pricing Examples With Production Tax Credit as Overnight Cost Reduction ($/kW) by Year

		2019	2020	2021	2022	2023*	2024*	2025*
TRG1	Overnight $/kW	$730	$687	$739	$787	$1,133	$1,075	$730
	Capacity Factor	50%	50%	51%	51%	52%	52%	53%
	LCOE $/MWh	$19	$21	$22	$23	$27	$26	$24
TRG5	Overnight $/kW	$840	$803	$839	$874	$1,208	$1,142	$1,075
	Capacity Factor	44%	45%	45%	46%	47%	48%	48%
	LCOE $/MWh	$25	$26	$27	$28	$31	$29	$28
TRG7	Overnight $/kW	$1,013	$991	$1,023	$1,054	$1,384	$1,313	$1,241
	Capacity Factor	35%	36%	37%	38%	38%	39%	40%
	LCOE $/MWh	$39	$40	$39	$39	$41	$39	$36

Source: based on LBNL 2014, 2018 NREL ATB

*No PTC Value

Solar Energy

Costs for fixed-tilt versus single-axis tracking solar projects are estimated to be approximately similar, with minor capital cost and maintenance cost differences; however, capacity factors are anticipated to increase significantly with single-axis trackers. NREL's ATB only evaluates single-axis tracking systems, with the best performing projects achieving an estimated 27% capacity factor (NREL ATB projects located in Daggett, CA). As a proxy for fixed-tilt solar projects, it is recommended that a 20% capacity factor be used (NREL ATB projects located in Kansas City, MO). NREL's ATB converts solar DC power to AC power output for capacity factor purposes, while keeping several financial metrics in $/kWDC units.

To provide a better range of pricing and performance, it is recommended that the "Mid" overnight costs for Kansas City and Daggett utility-scale solar projects from NREL's ATB should be used, along with the 20% and 27% capacity factors, respectively, beginning in 2019.

Due to guidance from the IRS, solar power projects that qualify for the 30% ITC in 2019, 26% ITC in 2020, or the 22% ITC in 2021 each have until the end of the year 2023 to become operational. A 10% ITC is available for projects that commence construction in or after 2022, and for projects that become operational in or after 2024. At the same time the federal ITC is slated to decline, the NREL ATB shows that solar power installed costs are anticipated to decline, almost in the exact same proportion as the ITC phaseout through 2023. Applying the ITC phaseout to the NREL ATB 2018 overnight capital costs, results in overnight costs of approximately $700/kWDC for projects that begin construction between now and 2021, which are also operational by the end of 2023. By 2024, when the bulk of the ITC has expired, solar pricing is anticipated to decline an equivalent amount, thus overall levelized cost of energy of utility-scale solar projects are anticipated to remain relatively flat from 2019-2030. For utility-scale solar projects with 20% capacity factors, and taking the ITC into account for near-term projects, overall LCOE is anticipated to remain in the mid-$30s/MWh range for the next decade. For projects with 27% capacity factors, LCOE values in the $20s/MWh are anticipated. SREA has worked with utility-scale solar development companies in the region who have corroborated the view that utility-scale projects in the Entergy region can be currently be delivered with an LCOE in the mid-$30/MWh range thanks to the ITC value and for the decade ahead with the forecasted future cost-declines following the ITC step-down to 10%.

NREL ATB Utility-Scale Solar Energy Pricing (ITC Included)

		2019	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*
Mid	Overnight $/kWdc	$707	$707	$707	$707	$707	$784	$775
	Capacity Factor AC	20%	20%	20%	20%	20%	20%	20%
	LCOE $/MWhAC	$32	$32	$32	$32	$32	$38	$38
Low	Overnight $/kWdc	$707	$707	$707	$707	$707	$784	$775
	Capacity Factor AC	27%	27%	27%	27%	27%	27%	27%
	LCOE $/MWhAC	$20	$20	$20	$20	$20	$24	$23

Source: NREL ATB 2018[20], 20-year LCOE, "Mid" is Kansas City, "Low" is Daggett

Other IRP Models Prove Entergy's Cost Assumptions are Too High

Two recent IRPs used better data assumptions than *Entergy's*. The Southwestern Electric Power Company (SWEPCO), with customers in Arkansas, Louisiana and Texas, recently completed its IRP in Arkansas.[21] 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 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.

Cleco's results are of particular importance to this Entergy IRP. Cleco uses the AURORA model, the same model Entergy uses. However, Cleco staff recognized AURORA had significant deficiencies due to its sole capacity-only focus. SREA made similar comments to Cleco regarding capacity-based planning and problems with AURORA, and Cleco accepted our recommendations. Cleco then made capacity adjustments in the AURORA model to make the software program perform more accurately. SREA recommended to Cleco that the company evaluate multiple configurations for renewable energy resources, including imports, as well as PPA-style agreements. Cleco agreed with and evaluated nearly all of SREA's recommendations. While Cleco incorporated stakeholder feedback to improve its IRP, Entergy has rejected SREA's recommendations.

Disputed Item #3: 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. 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 ELL's modeling assumptions even included the PTC or ITC. For example, ELL states in its Final IRP Report that, "The IRP is solving for a high-level indication of what types of capacity should be procured or investigated to meet ELL's long-term capacity need beginning in the mid-2020s. Accordingly, the PTC is assumed to have expired and the ITC is held constant at 10%." Again, Entergy's use of a capacity-based plan excludes the PTC and much of the ITC. However, the May 30, 2018 slide deck that ELL points to for renewable LCOE comparisons states that, "ITC normalized over useful life and steps down to 10% by 2023" and that the "PTC steps down to 40% by 2020 and expires thereafter" without any additional context.[22] As SREA has stated multiple times, at stakeholder meetings and in written comments, wind energy and solar power developers are safe-harboring projects so that they can deliver PTC or ITC qualified projects well into the mid-2020s.

ELL's duplicity on renewable energy costs means stakeholders cannot pinpoint the true data assumptions used in the IRP. It is entirely possible that ELL is excluding the PTC/ITC in model runs, while showing stakeholders totally separate "rosy" cost assumptions. This same problem occurred in the 2015 IRP where Entergy posted LCOE values for renewable energy including a spurious "match-up fee", double-counting cost of capital, and also included enigmatic transmission costs that ELL did not provide initially. SREA highlighted these problems in the 2015 IRP, indicating that ELL has a history of rejecting stakeholder input, but of also providing mixed assumptions.

Production Tax Credit

Wind energy developers can qualify projects for specific PTC vintages by commencing construction in a 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 2020 to begin operation, and still qualify for the full PTC. Projects that begin construction in 2017 have until the end of 2021 to become operational, 2018 projects by 2022, and 2019 projects by 2023. Renewable energy project developers frequently safe harbor qualified clean energy equipment, in anticipation of a future contract and reflect cost reductions in the proposals.

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.[23] 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 2020 (reflecting 100% of the PTC value), $500/kW for wind resources operational in 2021 (80% of PTC value), and $400/kW for wind resources operational in 2022 (60% of PTC value). Due to the high cost of tax equity for project financing, it is estimated that the 40% PTC (for projects that commence construction in 2019) is essentially value-less and not anticipated to be attractive to many wind developers.

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

	2019	2020	2021	2022	2023	Future
Wind PTC	$19.8/MWh	$19.8/MWh	$16.9/MWh	$14.2/MWh	No Value	0
OR Wind PTC (Overnight $/kW translated)	*$600/kW*	*$600/kW*	*$500/kW*	*$400/kW*	*No Value*	*0*

Source: Adaptation from LBNL 2014[24]

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 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.[25]

Most utility-scale solar energy projects will elect to receive the ITC. The ITC 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.[26]

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

Construction Begins	2019 Operation	2020 Operation	2021 Operation	2022 Operation	2023 Operation	Future Op.
Before 2020	30%	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[27]

Disputed Item #4: ELL Did Not Adequately Address Transmission

ELL did not evaluate out-of-state renewable energy opportunities. ELL stated "For the 2019 IRP, ELL did not include out of region as an alternative, as it is not expected that the relatively higher performance of remote generation would be significant enough to overcome several hurdles related to congestion and transmission related service charges. For more information, refer to Appendix G of ELL's 2015 IRP." Because the IRP rules require transmission solutions to be analyzed, ELL cannot simultaneously claim that transmission constraints exist and that the company will not evaluate possible transmission solutions.

SREA was involved in the 2015 IRP, and we objected then how ELL did their transmission analysis for out-of-state renewable energy imports. At the time, ELL chose the worst possible case for transmission congestion charges in 2015, and even then, those charges only added an additional $7.11/MWh for wind power delivered into MISO South.[28] SREA provided comment on that misleading analysis in 2015 (included in these comments as Appendix C). For this IRP, ELL did not perform any additional transmission analysis, and relying on bad analysis from 2015 to screen out-of-state renewable energy is unsatisfactory. ELL did not evaluate transmission solutions, yet the company claims that transmission is the constraint for receiving low-cost renewable energy resources.

SREA recommended that ELL should comment on the finalized MTEP19 retirement assumptions, and unit-specific information, as it relates to its own scenario-building process. ELL should fully utilize MISO's futures assumptions for its IRP, and retirement assumptions. ELL responded, "ELL designed the presented futures to reasonably bound possible outcomes and to provide a reasonable outlook on a range of potential market prices. ELL sees no reason to limit its IRP assumptions to those made in the MTEP process." However, it appears that MISO's Futures have a more holistic look at the footprint, in terms of what generators are likely to be retired over the time horizon evaluated. MISO collects information from all its members regarding actual retirement dates and uses other methodologies to determine possible retirement dates for units where a retirement date is not yet planned or is unknow.

Disputed Item #5: ELL Did Not Adequately Address Retirements

SREA recommended that ELL allow existing units to compete against new generation units, in an attempt to evaluate the economics of current generation units. ELL rejected SREA's recommendation. ELL stated that, "AURORA has the capability to assess deactivations in the capacity expansion algorithm, but there are data requirements which make this impractical within the scope of an IRP analysis." Again, ELL is using AURORA's deficiencies as justification for not conducting an accurate analysis.

ELL further stated that "Additionally, generally it is a reasonable assumption to expect maintaining an existing operating plant will be lower cost to customers than building a new generation facility, unless circumstances around the cost to maintain the facility, market conditions, or policy changes dictate a more detailed evaluation." This statement is totally counter to Entergy's "Portfolio Transformation Strategy", where the company touts the benefits of retiring older, inefficient, "Legacy" generation units in favor of newer units. Instead of assuming legacy units are better than newer units, an IRP is the tool to test that assumption.

Entergy uses a 60-year, 55-year and 50-year age methodology for retirement assumptions. ELL has noted that, "an Electric Power Research Institute (EPRI) analysis performed in 2012 projected that the average age of natural gas steam turbine retirements as of 2016 would be 52.9 years old. A 2017 study performed by the Lawrence Berkley National Laboratory (and supported by the Department of Energy) produced similar results finding that the most common age of recently retired natural gas steam turbines was between 40 and 50 years. This is consistent with the 52.4 years average life of the Entergy Operating Companies' natural gas steam turbines either deactivated or retired since 2000. Given these trends, there is risk that ELL's legacy gas units may not be economic or feasible to operate through their assumed 60-year useful life." As such, using 60-years as Entergy's "reference" case for existing legacy generation units in MISO, or even for itself, may be overly optimistic. It appears MISO has already corrected for this in its Futures. Also, ELL's analysis strongly suggests that its Futures scenarios are not all truly equal, and that while "An equal probability weighting per future is implicit within the framework of the risk assessment", such an approach is inadequate.

Stakeholders recommended ELL evaluate early retirement of several existing generation units. ELL responded, "While ELL maintains an interest in White Bluff, Independence and Big Cajun II, Unit 3, ELL is not the operator of these facilities. Given the nature of ELL's interest in these generating resources, ELL has not conducted additional scenarios/sensitivities using assumptions that differ from the guidance received by the resource owners. Furthermore, ELL believes that the Sierra Club would be better served by directing this portion of the comment to EAL and Cleco, rather than directing it to ELL." However, ELL's inherent futures assume that certain types of generators in the market retire after 50 years, 55 years, or 60 years, regardless of what those units resource owners recommend. In Future 3, ELL's "Market Coal & Legacy Gas Deactivation" assumption of 50 years may retire Cleco's Rodemacher coal-fired power plant before White Bluff or Independence are retired, despite no public retirement commitment from Cleco. Thus, ELL likely does deactivate units without commitments from resource owners, but only if resource owners are not Entergy subsidiary companies.

Disputed Item #6: ELL Devalues Solar Power

SREA recommended that capacity values for various wind energy and solar energy resources should be provided as a comparison against ELL'S peak load, as well as against MISO's peak load, in addition to MISO's wind energy and solar energy capacity valuations. ELL responded, "ELL's assumed solar capacity credit and wind credit are based on the MISO Tariff. Please see Table 10: Renewable Modeling Assumptions and Section "Solar Capacity Credit Modeling" for more information on assumptions used for solar and wind generation." MISO's capacity accreditation methodology constantly undergoes review and revision. As such, MISO's standard capacity accreditation is a static metric, and other methodologies may arise over time.

ELL recognized the limitations of MISO's capacity credit by creating its own "Solar Credit Step-Down" metric and using its own data for input in the Aurora model. But instead of performing an analysis, ELL claimed to use a "heuristic approach" for higher levels of solar energy penetration. This colorful linguistic approach is "a rule of thumb, an educated guess, an intuitive judgment, a guesstimate, profiling, or common sense."[29] Heuristics are shortcuts and are not reasonable nor valid data for modeling purposes. The implication for this specific heuristic approach is that solar power's capacity value declines, significantly, over time when compared to only the ELL system. SREA requested that ELL look at both wind and solar resources against its own peak load, as well as MISO's peak load. Such a request is mathematically simple; ELL would simply compare its actual hourly historical load, and the MISO actual hourly historical load, against actual hourly generation profiles for wind and solar. Because ELL and MISO's system peaks are not the same in duration or magnitude, one would expect to see some sort of differentiation between the two methodologies and two different energy resources. In such an analysis, because wind energy and solar energy have complimentary diurnal and seasonal patterns, one would expect that as solar power generation increases (and subsequently erodes a summertime afternoon peak), wind energy's capacity value should increase over time (as more winter peaks become more prevalent). In fact, ELL's draft IRP models verify this hypothesis by stating, "The capacity expansion algorithm selects at least 1 GW of solar before transitioning to adding solar and wind in concert. This could be due to the diminishing returns of solar capacity value, after which wind adds value to a portfolio containing solar by providing off-peak energy." Given that a 5% solar power penetration level for ELL's system represents a fraction of the full MISO system, solar power's total installed nameplate capacity for the entire MISO system would have to be significantly larger than ELL's system, alone. ELL never responded to these comments.

Further, ELL misrepresents MISO's work. ELL never cites where its "heuristic" concept is derived, but SREA is familiar with MISO's Renewable Integration Impact Assessment (RIIA) work. Currently MISO's RIIA is a work-in-progress and does not reflect an end-result, a final product, nor an adopted methodology by MISO. Even so, ELL's "heuristic" approach does not actually match MISO's own preliminary results. ELL's "heuristic" approach shows that solar power capacity credit would drop to approximately 10% at 30% penetration level of ELL's system. But MISO's RIIA results show that the effective load carrying capacity (ELCC) of solar power does not drop to 10% until after nearly 70,000 MW's of solar are added to the *entire* MISO system.

ELL's "Heuristic" Solar Capacity Assumptions

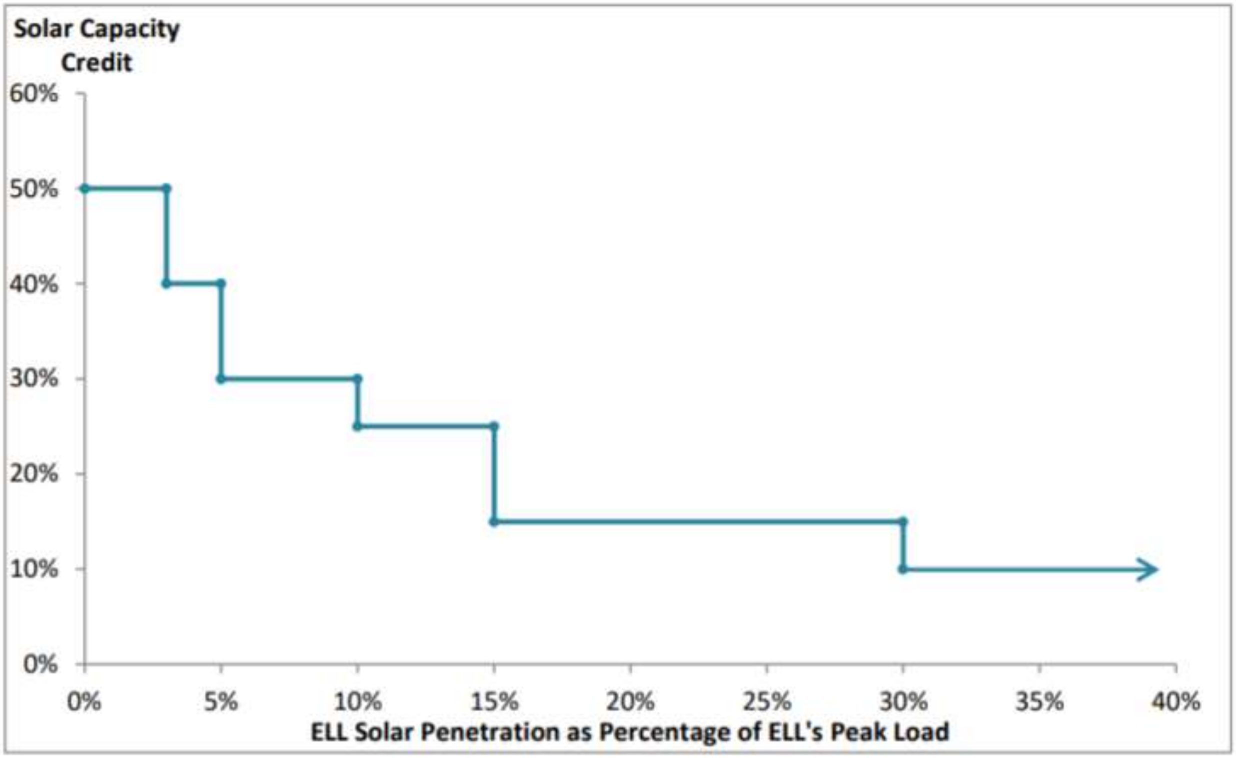
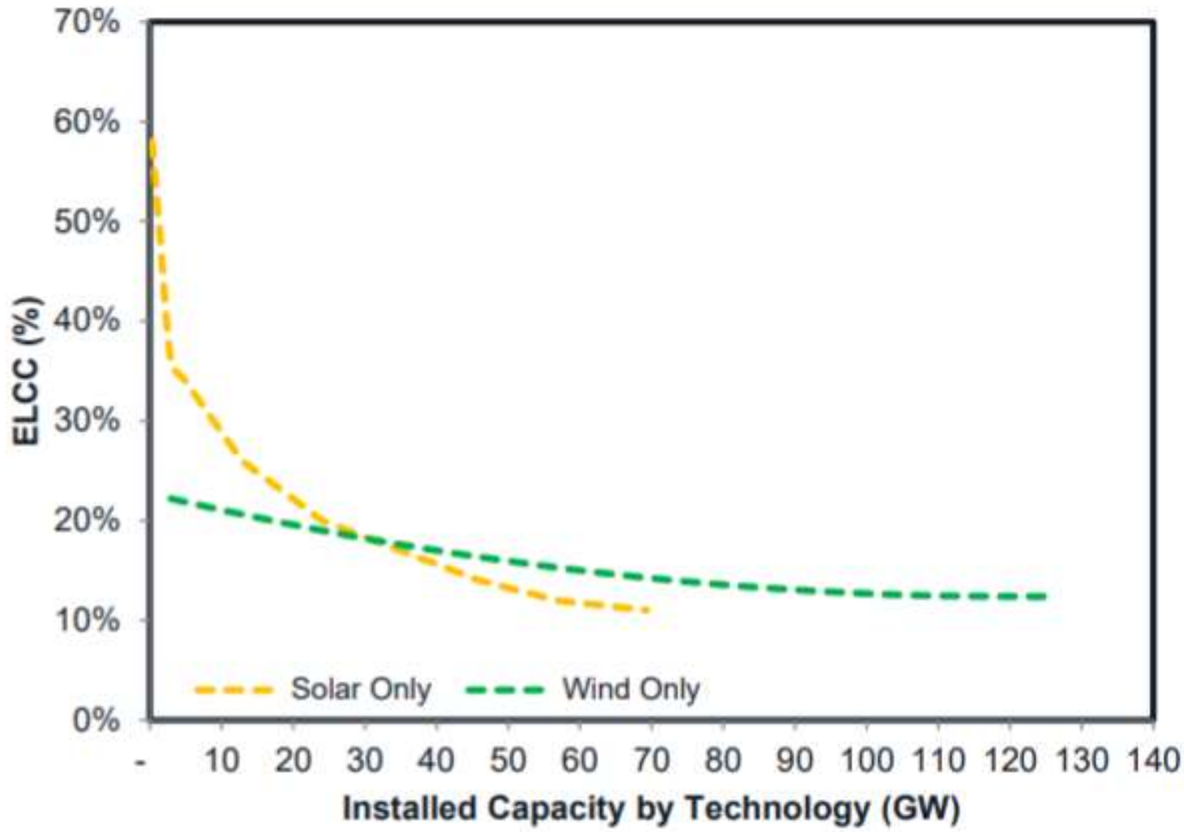


Figure 23: Solar Credit Step-Down as Penetration[20] Increases

MISO Renewable Integration Impact Assessment Results 2018



Source: MISO RIIA 2018[30]

MISO's RIIA study goes further to identify possible solutions to a degrading ELCC. Some solutions include incorporating both wind energy and solar energy together, adding energy storage resources, geographic diversity and even expanding transmission. ELL's refusal to evaluate transmission expansion in this IRP artificially constrains the ELCC for solar power, dealing double-damage to renewable energy resources. MISO has stated that "Under RIIA assumptions, most issues up to 20% renewables may be fixed by reconductoring only; integration complexity for 20% renewable milestone is in general relatively mild for MISO footprint in steady-state Operating Reliability." [31] Therefore, ELL's development of an inaccurate "heuristic" capacity value for renewable energy resources is premature.

Disputed Item #7: ELL Did Not Adequately Evaluate Energy Storage

SREA recommended that ELL use multiple energy storage configurations, including various capacity/energy configurations, multiple revenue streams and as stand-alone projects as well as coupled with generation resources (such as renewable energy resources). ELL's response was "Specific resource sizing decisions are properly addressed in the detailed evaluations that are performed prior to selecting a resource. Coupling these resources would not improve the economics within the IRP evaluation of these alternatives. The nuanced benefits of coupling batteries and intermittent resources will continue to be explored on a case-by-case basis."

However, ELL's "heuristic" approach to evaluating capacity value for solar power would radically change if energy storage and solar power were combined.

SREA recommended that ELL use sub-hourly dispatch modeling. ELL's response was "While the AURORA model has the capability to simulate sub-hourly time intervals, the analysis is prohibitively time consuming considering the scope and strategic objectives of the IRP analyses." ELL had over four months to develop the draft IRP between the time Stakeholder Comments were due in May 2018 and the draft IRP was published in October 2018. In that same amount of time, Entergy Arkansas' entire IRP process took place, from beginning to end, suggesting that modeling runs do not take substantial amounts of time currently. Of course, sub-hourly planning will take more time to model; however, the MISO market already functions on a subhourly basis, and because of the unique attributes of energy storage economics, subhourly planning is the only way to adequately evaluate that resource technology. Perhaps other, better and updated software could more efficiently model subhourly dispatch.

Disputed Item #8: ELL Violated LPSC IRP Rules

The IRP rules state that "An electric utility's IRP shall be relied on by the utility as it creates its internal business plans." However, this IRP would lead to ELL to "do nothing" over the next five years. Meanwhile, Entergy has provided its investors more details than the company is providing in this filing. Entergy states:

> "Entergy is investing approximately $11 billion in capital over the next three years in generation assets and transmission and distribution infrastructure. Initiated in 2002, Entergy's portfolio transformation strategy incorporates cleaner, more efficient generation sources, allowing the retirement of older, less efficient legacy units. Due to this strategy, we have replaced nearly 30 percent of our older generation with cleaner, more efficient resources, and natural gas now represents approximately 60 percent of our current utility generation capacity. Entergy also works to preserve our nuclear assets and has set a goal of integrating approximately 1,000 MW of renewable energy sources into our utilities' respective generation supply portfolios over the next several years, further reducing the company's already low CO2 emission rate."[32]

The IRP rules state that resource planning ought to focus on the lowest reasonable cost, but that with proper justification, the utility may select plans "that are not exclusively least cost, for example, if the utility is able to justify that such selection is consistent with reliability, planning, regulatory, environmental and operational objectives or constraints, and will reduce the risk of customers incurring higher costs under certain scenarios." ELL is within its defined ability to select a higher-cost resource portfolio, as its current IRP does; however, ELL has not adequately justified its decision. ELL could reduce overall costs by reducing energy production from certain existing generation units, and instead procuring low-cost renewable energy resources.

The IRP rules state that ELL is allowed to provide a screening test for new supply-side technologies, such as solar and wind, and "a common practice in screening supply-side alternatives is to compare alternatives based on a levelized cost or a present value analysis." ELL excluded evaluation of renewable energy from outside of the ELL service territory, specifically imported wind energy resources. ELL also excluded evaluating PPA's for renewable energy. ELL did not evaluate "hybrid" renewable systems, or systems that incorporate multiple technologies such as solar plus storage.

The IRP rules state that, "Capacity upgrades and retirements of existing supply-side resources are issues typically considered in a utility's IRP." However, ELL has explicitly eschewed evaluating retirements in this IRP. The LPSC has now stepped in and is requiring ELL to conduct an entirely separate "legacy" study, outside of the scope of this IRP (and outside the review of this IRP's stakeholders), when ELL should have included retirements in this study from the beginning. That being said, ELL's filing of a new retirement study will effectively hit the reset button on this IRP and warrants an updated IRP process.

ELL excluded transmission analysis from this IRP. However, the IRP rules state that, "Typically all generation resources will require transmission costs and those costs should be considered in the analysis. At times, there may be large transmission projects that could provide access to economic generation resources, and it may be desirable to treat those projects as separate resource options in the optimization process." At the second stakeholder meeting, an Entergy representative stated, "The AURORA isn't a transmission planning model." If AURORA is unable to conduct transmission planning, ELL should not be allowed to solely rely on that single software program to conduct its IRP.

The IRP rules set specific requirements regarding transmission evaluations. Specifically, "The IRP shall include the most recent longterm transmission plan and planning study prepared by the entity charged with performing transmission planning pursuant to the effective FERC jurisdictional open access transmission tariff. Unless this information is included in the transmission planning study provided, the utility shall identify and describe significant transmission constraints and limitations within its system, and identify and describe any Reliability Must Run ("RMR") units that it operates. Furthermore, the utility shall discuss any actions that could be taken to eliminate the constraints, limitations, and RMR units." ELL has not identified any RMR units. Transmission solutions could identify minor upgrades to not only increase reliability, but also to provide better access to low cost power or provide new routes to dispatch power to other utilities. A stronger connection between MISO North and South would better enable power flows between the regions to reduce the risks of maximum generation events, as well as access low-cost renewable energy resources. ELL has never responded to this comment.

The IRP rules require sensitivity analyses. Specifically, the rules state, "The reference resource plan is further analyzed by conducting sensitivity and scenario analyses. The purpose is to examine how the reference plan would be affected by changes in input assumptions, and to evaluate alternative resource plans that would be more economic based on different assumptions. As a result of these analyses, modifications may be made to the reference resource plan." It is unclear that ELL has complied with this requirement. Specifically, the IRP rules state that: "Sensitivity analyses shall be performed to determine the risk that the reference resource plan might be exposed to unacceptable cost increases under certain conditions, and to evaluate alternative resource plans that would be more economic given the alternative assumptions. Though other assumptions may be considered, the following are often evaluated in sensitivity analyses in utility IRP studies: (1) fuel prices; (2) loads; (3) capital costs for new generation resources; (4) inflation and other financial parameters; (5) probable costs of environmental regulations." ELL did not evaluate sensitivities for various renewable energy generation resources. ELL states, "Meaningful sensitivities are incorporated within *the futures and focus on inputs that impact ongoing market prices.* To the extent development cost assumptions change, these costs would be incorporated through subsequent planning processes, IRPs, and procurement activities." (emphasis added) It is important to note that the futures ELL developed are scenarios, and are not sensitivities.

The IRP rules require that the Final IRP Report include, "For each potentially feasible supply-side resource option identified for further examination, the utility shall include in its IRP Report at least the following information: (1) Description of the option; (2) Resource type; (3) Capacity; (4) Fuel type; (5) Heat rate and availability; (6) Ownership information; (7) Location (if identified); (8) Anticipated life: (9) Operating costs, including O&M, property taxes and capital additions; (10) Capital Cost and AFUDC assumption; (11) Potential environmental costs associated with the operation of the resource during the planning period; and, (12) Any other information deemed pertinent by the utility." These data and assumptions were not provided for renewable energy resources in the Final IRP report, even though ELL referred to a slide deck it filed separately of its report.[2]

The IRP rules require, "IRP Report shall include a description of all models and methodologies used in performing the IRP, along with the utility's reasons for choosing those models and methodologies." ELL did not explain why it believes the IHS renewable energy data are better than SREA's data, and ELL did not explain why the AURORA model is the best model for this IRP, despite SREA's voluminous comments to the contrary.

ELL failed to conduct a robust analysis. ELL did not provide assumptions regarding wind turbine type, turbine height, turbine capacity, or rotor diameter. ELL did not conduct any analysis regarding importing renewable energy resources from outside of Louisiana. ELL did not evaluate alternative financial structures for renewable energy procurement, such as PPA's. ELL only evaluated self-own or self-build generation technologies. Each of the decisions mentioned previously affect overall renewable energy costs, and the assumptions and methodologies chosen by Entergy pancake cost increases for renewable energy generation in their assumed models.

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[2] ELL provided installed cost assumptions for wind energy and solar power in Figure 15, pg. 43 of the Final IRP Report; however, the values provided are redacted from public view. Meanwhile, ELL referred to a slide deck it published on May 30, 2018 in its Final IRP Report regarding LCOE; however, the data provided in that slide are not in the Draft IRP Report, nor the Final IRP Report.
Entergy (May 30, 2018). Data Assumptions and Study Description, 2019 ELL Integrated Resource Plan. [https://www.entergy-louisiana.com/userfiles/content/irp/2019/ELL_2019_IRP_Assumptions.pdf]

The IRP rules require that the Final IRP Report include specific details for the Action Plan. Per the IRP rules, the Action Plan shall include "a description of the activity, the amount of capacity involved, when the activity is projected to be completed, and other details that the utility deems relevant." ELL has vaguely mentioned it plans to do some sort of renewable RFP sometime in the next five years.

The IRP rules were intended "to encourage a collaborative working process with stakeholders"; however, while ELL has responded to comments provided by stakeholders, ELL has not collaboratively worked with stakeholders. SREA noted in our comments to the Draft IRP on January 23, 2019 that "it appears that over 70% of the requests or recommendations by Stakeholders have been entirely rejected. The remaining 30% of comments that were not rejected were mostly some variation of 'See Section ….' or that the IRP 'addresses this'. No response by ELL indicated that a Stakeholder's comment materially improved or changed the IRP report." As such, our comments to the Draft IRP closely mirrored our original comments with additional materials. ELL did not respond to, or disagree, with our assessment in the Final IRP. Much of ELL's responses to in this Final IRP Report similarly dismiss stakeholder feedback.

No response by ELL indicated that a Stakeholder's comment materially improved or changed the IRP report. As for the deficiencies, the Draft IRP and Final IRP did not include or address:

- Multiple wind energy resources
- Multiple solar energy resources
- Renewable hybrid systems
- Hybrid renewables plus energy storage systems
- Renewable PPA's
- Transmission expansion opportunities
- Renewable energy tax credits
- FERC Order 841
- Subhourly planning
- Ancillary benefits for battery storage
- Modeling software deficiencies
- An RFI for renewable energy benchmarking

SREA participated in the Second Stakeholder Meeting, held in November 2018. Prior to the meeting, ELL staff requested that Stakeholders submit questions prior to the meeting. SREA, along with other Stakeholders, submitted lists of questions. However, at the Stakeholder meeting itself, ELL staff did not answer the submitted questions or rejected stakeholder requests. SREA requested a significant amount of data in user-friendly format; however, such requests have been either been ignored or rejected. Meanwhile, SREA was able to find much of the data via publicly available resources; indicating that this Stakeholder process is being made intentionally difficult.

The IRP rules require, "Regardless of whether the utility adopts the [stakeholder] recommendations, the utility shall include a section in the IRP Report documenting all of the stakeholder's recommendations and explaining the Company's reasons for accepting or rejecting each recommendation." ELL did not explicitly state that it accepted or rejected any stakeholder comments. Based on SREA's evaluation, we can not determine that ELL accepted any stakeholder comment that would have materially affected ELL's original data, modeling, or results.

Review of the Overall IRP Process and Impending RFP

SREA's participation in the 2015 IRP process for ELL followed a similar trajectory as this IRP. After the publication of the Final IRP, significant time and effort had been made to assist in resolving the deficiencies of that IRP; however, such recommendations were similarly rejected. Instead of developing a new IRP, or having the LPSC develop a procedural hearing schedule, ELL offered to issue a 200 MW Request for Proposals (RFP) for renewable energy resources. At the time, SREA believed issuing an RFP would help resolve many of the disagreements and discrepancies and were encouraged by the RFP moving forward. However, between the exceptionally long process (over two years) and the inflexibility of the technology offerings, the RFP process was not designed for success. Here, four years after that 2015 IRP process, ELL still has not installed or procured significant quantities of renewable energy resources and is planning on filling a fraction of its original RFP. Entergy's mishandling of the RFP process, as well as the IRP process, has led to skepticism and distrust in the renewable energy industry. As such, Entergy is losing opportunities to access some of the best, and lowest cost, renewable energy resources as the industry turns to more favorable customers to sell projects.

It seems that Entergy is aware of the deficiencies of its IRP modeling procedures. In the EAI IRP, that utility found no capacity need, yet EAI issued a 200 MW RFP for solar.[33] In the EMI IRP, that utility found no capacity need in the near term, yet EMI announced a new 100 MW solar PPA.[34] ENO recommended recently that the New Orleans City Council adopt a 70% Clean Energy Standard, and announced that the utility plans on "adding up to an additional 240 MW of large-scale solar PV resources"[35], despite the IRP not finding a need for renewable energy in the near-term. Entergy Texas (ETI) does not have a public IRP process, but ETI also issued a 200 MW RFP for solar power.[36] Even the 2015 ELL IRP did not identify a need for renewable energy resources, but ELL issued a 200 MW RFP for renewable energy, and will be procuring 50 MW of solar energy soon.[37] Even with the 50 MW solar power addition, ELL lags behind nearly every other Entergy subsidiary company for renewable energy procurement. Overall, it appears Entergy's renewable energy procurement strategy necessarily falls entirely outside of IRP processes, due to the inherent problems of capacity-only planning.

ELL's 2016 Renewable Energy RFP suffered from major framework flaws that resulted in a lackluster endpoint. ELL confined the RFP to 100 MW's wind energy and 100 MW's solar energy, then further split those resources down to 50 MW's for each individual PPA. Smaller-sized PPA's tend to result in higher overall costs. Comparatively, EAI plans to procure 281 MW's of solar energy in the very near term and issue an additional 200 MW RFP. One primary difference for EAI is its ability to conduct an RFP in a reasonable timeframe. ELL's RFP process effectively began with the 2015 IRP, and the resultant solar PPA will come online nearly five-years later. Renewable energy development companies are capable of delivering projects much sooner than a five-year process, and a longer process makes it more difficult to finance projects. The previous RFP was too prescriptive, took too long, and the results show that that process was a failure. Now, in this IRP, Entergy offers vague and conflicting information about when it plans to issue a renewable RFP. In some parts of the IRP, the company states it plans to issue an RFP in the next five years. In another part of the IRP, the company states it will issue the RFP in 2020.

Recommendations

Good integrated resource planning serves as an advanced notice of opportunity and of danger. If the old forecasting maxim holds that garbage in becomes garbage out, the Entergy's IRP represents significant danger to Louisiana. Substantial change in this IRP process is necessitated to avoid this similar behavior from repeating itself in the future. SREA has recommendations that, if implemented, would greatly improve Entergy's IRP and the IRP process.

Recommendation #1: Reject ELL's 2019 IRP

There are too many deficiencies in this IRP and this IRP process for it to be redeemed by minor fixes. The LPSC has the ability to reject an IRP and in doing so, it would send a message to Entergy that its practices are deficient.

Recommendation #2: Require a new IRP

In rejecting the IRP outright, the LPSC would create a clean slate that will need parameters for Entergy and stakeholders to follow. SREA would invite an evidentiary hearing and litigated IRP process.

Recommendation #3: Update IRP Rules

Louisiana's IRP process is exceptionally long, and may be one of the longest IRP processes in the country. Given Entergy's refusal to update its assumptions based on stakeholder feedback, by the time the IRP is finalized, it relies on outdated information. SREA recommends opening a docket to discuss IRP rules to be updated.

Through this IRP process, there are few if any enforcement mechanisms. As such, there is virtually no downside for Entergy to simply ignore the IRP rules and stonewall stakeholder feedback. With an updated IRP process, SREA recommends developing penalties or other enforcement mechanisms. For instance, the Commission could offer two IRP tracks: one track for an open, collaborative process (as currently envisioned), and another track as a litigated process. If a utility does not participate collaboratively, the Commission could require a litigated IRP for the *next* process. If the Commission conducts a litigated IRP, and is satisfied at the end of the process, a utility could be allowed to return to the non-litigate process for the next IRP.

Recommendation #4: Expedite a Renewable Energy RFP

Entergy has stated it plans to procure at least 1,000 MW's of renewable energy as part of its corporate sustainability practices. All other Entergy subsidiaries have released renewable energy requests for proposals very recently, or announced new renewable energy procurement.

Entergy Louisiana has not issued a new renewable RFP, nor announced new renewable energy procurement, beyond what was announced at the end of the 2015 IRP process. Issuing a large, flexible RFP for renewable energy resources in the near term would help capture cost savings from the expiring federal renewable energy tax credits. SWEPCO has already released a 1,200 MW RFP for wind energy. Cleco plans to issue a 500 MW RFP for renewable energy later this year. Therefore, SREA recommends Entergy release a 1,000 MW RFP for renewable energy, for projects delivered in the next few years.

Recommendation #5: Create an "Additional Sum" for Renewable Energy

Entergy, like many other utilities across the country, financially motivated to self-build and self-own generation assets. While not stated explicitly in this IRP, ELL's financial motivation may have led to modeling only self-own and self-build power generation. To resolve this mismatch of financial motivation versus purchasing lower-cost power from independent power producers, some states are creating new regulatory structures to incentivize lower operational costs. For example, in Georgia the Georgia Power Company may earn up to 8.5% off the net cost benefit of power purchase agreements compared to avoided cost as an "additional sum". This additional sum is a negotiated figure based on a litigated integrated resource plan.[38] Georgia receives exceptionally low renewable energy power prices because the state promotes competitive bidding, and those low prices are then passed along to ratepayers.

This concept of an "additional sum" has also been adopted in Arkansas. The Arkansas Public Service Commission approved a solar power purchase agreement for Entergy Arkansas Inc. (EAI) and stated that, "it is reasonable to allow EAI to recover an 'Additional Sum' of 20 percent of the actual annual savings achieved by the Chicot [solar] PPA…"[39] This "additional sum" construct encourages Entergy Arkansas to find the lowest cost renewable energy option in order to maximize the actual savings for ratepayers while also creating a new revenue stream for the company. SREA is in favor of supporting a revenue mechanism that encourages ELL to reduce ratepayer costs while purchasing new, low-cost renewable energy resources, like an additional sum.

Conclusion

The Southern Renewable Energy Association appreciates the opportunity to engage in integrated resource planning in Louisiana. The Louisiana IRP process can achieve its ideals of a collaborative process, but only if stakeholders have a willing partner. SREA has been impressed with both the Southwestern Electric Power Company's (SWEPCO's) and Cleco's willingness to work with stakeholders through their respective IRPs. However, Entergy's IRP process has been uncooperative. Many of the same problems SREA identified with the ELL 2015 IRP have manifested four years later. SREA looks forward to working with the LPSC on this and future IRPs.

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Appendix A: Entergy Louisiana Existing Generation Fleet Statistics 2018

Company	Plant	Unit	ETR %	COD	MW	Fuel	Status	BTU/KWH	MWH Gen	Exp/MWH	$,000's	CF%
ELL	Acadia	2	100%	2002	551	Gas	Intermediate	7,265	2,932,742	27.2	79,830	61%
ELL	Buras	8	100%	1971	11	Gas/Oil	Peaking	20,410	3,199	92.0	294	3%
ELL	Little Gypsy	2	100%	1966	412	Gas/Oil	Intermediate	11,515	1,618,194	48.7	78,878	20%
ELL	Little Gypsy	3	100%	1969	517	Gas/Oil	Intermediate					
ELL	Ninemile Point	4	100%	1971	729	Gas/Oil	Intermediate	9890	4,693,351	38.0	178,280	36%
ELL	Ninemile Point	5	100%	1973	745	Gas/Oil	Intermediate					
ELL	Ninemile Point	6	100%	2014	560	Gas/Oil	Intermediate	7,138	4,567,269	28.7	131,056	93%
ELL	Perryville	1	100%	2002	528	Gas	Intermediate	7,040	3,841,364	28.8	63,111	64%
ELL	Perryville	2	100%	2001	152	Gas	Peaking					
ELL	Sterlington	7	100%	1974	47	Gas/Oil	Peaking	13,881	3142	357.6	1,124	1%
ELL	Waterford	1	100%	1975	411	Gas/Oil	Intermediate	10,733	1,613,750	45.2	72,951	21%
ELL	Waterford	2	100%	1975	428	Gas/Oil	Intermediate					
ELL	Waterford	4	100%	2009	33	Oil	Peaking					
ELL	Willow Glen	2	100%	1964	-	Gas/Oil	Retired					
ELL	Willow Glen	4	100%	1973	-	Gas/Oil	Retired					
ELL	Roy S. Nelson	4	100%	1970	425	Gas/Oil	Retired					
ELL	Calcasieu	1	100%	2000	144	Gas	Peaking	11,227	257,094	68.3	17,562	14%
ELL	Calcasieu	2	100%	2001	159	Gas	Peaking					
ELL	Ouachita	3	100%	2002	245	Gas	Intermediate	7,261	1,348883	28.4	38321	63%
ELL	Roy S. Nelson	6	40%	1982	221	Coal	Base	11,508	1,131542	33.3	37703	58%
ELL	Big Cajun 2	3	24%	1983	140	Coal	Base	10,975	687,742	38.8	26,690	56%
ELL	River Bend	1	100%	1986	967	Nuclear	Base	10,933	6,999,996	34	237,856	83%
ELL	Waterford	3	100%	1985	1,168	Nuclear	Base	10,773	10,298,128	23.6	242,562	101%
ELL	Union Power	3	100%	2003	502	Gas	Intermediate	7,303	499,9401	30.9	154,337	57%
ELL	Union Power	4	100%	2003	501	Gas	Intermediate					

Entergy (2019). Entergy Statistical Report and Investor Guide 2018.

Appendix B: Other Entergy Existing Generation Fleet Statistics

Company	Plant	Unit	ETR %	COD	MW	Fuel	Status	BTU/KWH	MWH Gen	Exp/MWH	$,000's	CF%
EAI	Independence	1	32%	1983	263	Coal	Base	10,149	1,559,109	24.6	38,315	68%
EAI	White Bluff	1	57%	1980	465	Coal	Base	10,469	4,703,562	27.4	128,962	58%
EAI	White Bluff	2	57%	1981	468	Coal	Base					
EAI	ANO	1	100%	1974	833	Nuclear	Base	10,386	12,720,893	32.5	412,431	80%
EAI	ANO	2	100%	1980	985	Nuclear	Base					
EAI	Ouachita	1	100%	2002	252	Gas	Intermediate	7,308	2,672,636	28.1	75,152	60%
EAI	Ouachita	2	100%	2002	253	Gas	Intermediate					
EAI	Hot Spring	1	100%	2002	606	Gas	Intermediate	7,301	3,433,636	29.6	101,532	65%
EAI	Union	2	100%	2003	507	Gas	Intermediate	7,241	258,8157	27.0	69,883	58%
EAI	Lake Catherine	4	100%	1970	528	G/O	Peaking	11,588	288,819	100.0	28,893	6%
EAI	Carpenter	1	100%	1932	30	Hydro	Peaking		123,179	8.7	1,076	23%
EAI	Carpenter	2	100%	1932	30	Hydro	Peaking					
EAI	Remmel	1	100%	1925	4	Hydro	Peaking		36,968	32.6	1,206	35%
EAI	Remmel	2	100%	1925	4	Hydro	Peaking					
EAI	Remmel	3	100%	1925	4	Hydro	Peaking					
EMI	Attala	1	100%	2001	453	Gas	Intermediate	7,191	2,204,189	29.4	64,724	56%
EMI	Hinds	1	100%	2001	460	Gas	Intermediate	7,039	3154,832	26.2	82,591	78%
EMI	Baxter Wilson	1	100%	1967	532	Gas/Oil	Peaking	10453	946,825	43.9	41,578	10%
EMI	Baxter Wilson	2	100%	1971	531	Gas/Oil	Peaking					
EMI	Gerald Andrus	1	100%	1975	729	Gas/Oil	Peaking	11534	854,269	48.7	41,598	1%
EMI	Rex Brown	3	100%	1951	29	Gas/Oil	Peaking	12497	1,583,41	67.6	10,709	8%
EMI	Rex Brown	4	100%	1959	200	Gas/Oil	Peaking					
EMI	Rex Brown	5	100%	1968	9	Oil	Peaking					
EMI	Independence	1	25%	1983	204	Coal	Base	10336	2,420,796	25.8	62,494	67%
EMI	Independence	2	25%	1984	211	Coal	Base					
ENO	Union Power	1	100%	2003	491	Gas	Intermediate	7295	2,734,812	27.9	76,333	64%
	NOLA Solar	1	100%	2016	1	Solar	N/A		1,518	44.3	67	17%
SERI	Grand Gulf	1	90%	1985	1,272	Nuclear	Base		7,019,913	39.6	277,989	63%
ETI	Roy S. Nelson	6	30%	1982	164	Coal	Base	11508	836,356	34.8	29,098	58%
ETI	Big Cajun 2	3	18%	1983	102	Coal	Base	10975	508,334	38.8	19,724	57%
ETI	Lewis Creek	1	100%	1970	251	Gas/Oil	Intermediate	10868	1,996,352	41.1	82,117	45%
ETI	Lewis Creek	2	100%	1971	252	Gas/Oil	Intermediate					
ETI	Sabine	1	100%	1962	212	Gas/Oil	Intermediate	10707	4,191,510	41.1	172,381	33%
ETI	Sabine	3	100%	1966	268	Gas/Oil	Intermediate					
ETI	Sabine	4	100%	1974	534	Gas	Intermediate					
ETI	Sabine	5	100%	1979	449	Gas/Oil	Intermediate					

Entergy (2019). Entergy Statistical Report and Investor Guide 2018.

APPENDIX C
Southern Wind Energy Association
P.O. Box 1842, Knoxville, TN 37901

October 31, 2015

Ms. Melanie Verzwyvelt
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North Fifth Street
Baton Rouge, LA 70821-9154

RE: LPSC Docket No. I-33014. Transmission Analysis for Disputed Items for Entergy Louisiana, LLC and Entergy Gulf States Louisiana LLC Final Integrated Resource Plan ("IRP"),

Dear Ms. Verzwyvelt,

The Southern Wind Energy Association (SWEA) has conducted a transmission analysis for the Louisiana Public Service Commission. This analysis is in response to the Docket No. I-33014, for the Entergy Louisiana, LLC and Entergy Gulf States Louisiana LLC Final Integrated Resource Plan (IRP). In the Final IRP, wind energy transmission costs were provided; however, no clear methodology nor data was provided.

SWEA conducted its own transmission analysis based on hourly load data for the Entergy System and locational marginal pricing data (LMP) for fourteen different wind farms sited throughout the Southwest Power Pool (SPP). Hourly load data from 2007-2012 for the Entergy System are publicly available via the Federal Energy Regulatory Commission form 714 data. Those data were compared against various wind farm nodes within the SPP footprint, the SPP/Entergy System interface, and the two nodes used in the Final IRP, EES.EGILD and EES.ESLILD from September 1, 2014 to August 31, 2015. LMP data were not available for EES.EGILD and EES.ESLILD from March 1 to May 26; average week prior and average week after LMPs were used in place of the absences. All results were averaged and load-weighted. SWEA's LMP differential results for the Spearville, Centennial and Keenan wind farms are virtually the same as the Final IRP results, see Figure 1 below.

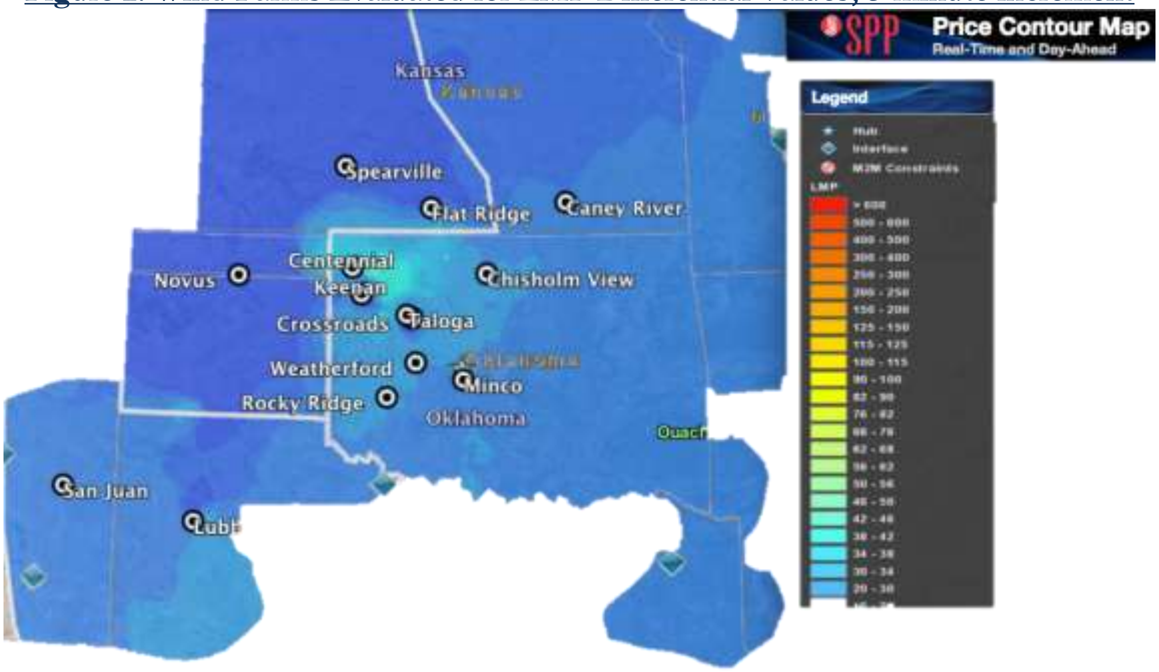
Figure 1. LMP Differential Result Comparison

Wind Farm	Final IRP Results	SWEA Results
Spearville	$12.92	$12.55
Centennial	$17.07	$16.59
Keenan	$13.84	$14.84
Average	$14.60	$14.66

The minor differences between the Final IRP and SWEA's LMP differential results is likely due do the different timeframes of the data analyzed.

The three wind farms evaluated for the Final IRP (Spearville, Centennial and Keenan) are in some of the worst congested areas within SPP. As such, these three wind farms do not represent a fair analysis for LMP differentials. SWEA evaluated the three wind farms, in addition to eleven other wind farms within SPP. Figure 2 shows the fourteen total wind farms plotted against a recent LMP contour map from SPP.

Figure 2. Wind Farms Evaluated for LMP Differential Values, 5-minute increment



As mentioned previously, SWEA evaluated the individual and average LMP differentials compared against EES.EGILD and EES.ESLILD, but also the SPP/Entergy interface. Contractually, wind energy could be delivered to the SPP/Entergy interface and then Entergy would obtain network service via MISO. Energy delivery to the interface, as opposed to EES.EGILD and EES.ESLILD, is a significantly lower-cost option, see Figure 3.

Figure 3. Various LMP Differentials Based on Wind Farm Site and Energy Delivery Point ($/MWh)

	EES.EGILD	EES.ELILD	Avg. ESS	SPP-EES INTERFACE
Spearville	$13.16	$11.93	$12.55	$4.51
Centennial	$17.21	$15.98	$16.59	$8.56
Kennan	$15.45	$14.22	$14.84	$6.80
Caney River	$8.32	$7.09	$7.71	-$0.33
Weatherford	$5.56	$4.34	$4.95	-$3.08
Chisholm View	$7.32	$6.10	$6.71	-$1.33
Minco	$6.02	$4.79	$5.40	-$2.63
Taloga	$4.64	$3.41	$4.03	-$4.01
Crossroads	$11.91	$10.69	$11.30	$3.26
Novus	$13.17	$11.95	$12.56	$4.52
San Juan	$3.47	$2.24	$2.85	-$5.18
Lubbock	$4.97	$3.74	$4.36	-$3.68
Rocky Ridge	$6.51	$5.29	$5.90	-$2.13
Flatridge	$8.26	$7.03	$7.64	-$0.39
Averages	$9.00	$7.77	$8.38	$0.35

As can be seen in Figure 3, the three wind farms selected for LMP differential analysis (Spearville, Centennial and Keenan) are some of the highest cost wind projects evaluated. When taking other projects into consideration, the cost estimate used in the Final IRP of $14.60/MWh is roughly 74% higher than the average LMP differential for delivery into the average between EES.EGILD and EES.ESLILD. If Spearville, Centennial and Keenan are removed from analysis, the Final IRP LMP differential price is 119% higher than other wind farm sites.

As a secondary delivery option, Figure 3 shows energy delivery to the SPP-EES (Entergy) Interface. Most wind farms evaluated show a negative LMP differential, indicating a source of revenue. The average LMP differential for the fourteen wind projects is just $0.35/MWh, indicating that the Final IRP LMP differential price to be over 4,000% too high. If the three wind farms evaluated in the Final IRP are excluded, the average LMP differential price for the eleven projects evaluated is -$1.32/MWh. This figure is in line with what the Georgia Power Company (GPC) found in its analysis of various wind farm proposals submitted via its Request for Information (RFI) earlier this year, see the transmission cost results of the GPC RFI in Figure 4.

Figure 4. Example Average Oklahoma and Kansas Transmission Delivery Charges to the Southern Balancing Authority

	Example Oklahoma Wind Generator		Example Kansas Wind Generator	
	Congestion	Losses	Congestion	Losses
MISO	$1.44	$1.66	$3.76	$1.93
SPP	$ (1.21)	$ (0.10)	$6.82	$1.88

Source: GPC RFI February 2015[1]

Figure 4, adapted from the GPC RFI, corroborates SWEA's results, that example wind generators within SPP represent very low LMP differentials for energy imported eastward.

The Final IRP LMP differential analysis is biased against wind energy and used unrealistically congested wind projects for evaluation. This unrealistic transmission analysis was coupled with excessively high levelized cost of energy (LCOE) wind energy prices in the Final IRP. This analysis and SWEA's previous analyses show that wind energy can provide great value to Louisiana ratepayers. Please consider requiring the Final IRP models to be re-run with up-to-date information about wind energy.

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[1] Georgia Power Company (February 27, 2015). Report Summarizing the Responses Received and Georgia Power's Filings Regarding Opportunities for Additional Wind Generation Resources [http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=157251]