COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC 2024 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 2024-00326

SOUTHERN RENEWABLE ENERGY ASSOCIATION WRITTEN COMMENTS UPON 2024 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

WITH

NOTICE CONCERNING CONFIDENTIAL INFORMATION

Comes now the Southern Renewable Energy Association (also "SREA"), by and through counsel, and files its Written Comments upon the 2024 Joint Integrated Resource Plan ("IRP") of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU" collectively "Companies") into the record in the instant case. For its written comments and recommendations, SREA is sponsoring a report prepared by Akarsh Sheilendranath (Principal) and Peter Heller (Energy Research Associate) of the Brattle Group (Attachment A).[1]

I. SREA

SREA is a non-profit regional trade association that works to promote the responsible development and use of utility-scale wind energy, solar energy, energy

[1] The *curricula vitae* of Akarsh Sheilendranath and Peter Heller can be found at Exhibits 2 and 3 of the Brattle Group Report (Attachment A).

storage, and transmission solutions throughout the South. Its vision is for renewable energy to become a leading source of energy in the South and our mission is to promote responsible use and development of renewable energy in the South. SREA's geographic region covers seven Southeastern states: Alabama, Arkansas, Georgia, Kentucky, Louisiana, Mississippi, and Tennessee. To achieve its vision, SREA frequently engages in IRP processes throughout the southeast, including Kentucky.

SREA is grateful to the Kentucky Public Service Commission for allowing it the opportunity to provide these written comments into the record of the Commission's forward-looking, cooperative resource planning process. The objective of these written comments is to exchange information and ideas in a less adversarial manner to best serve the interests of the parties, the stakeholders, and the Commonwealth of Kentucky in resource planning.

II. BRATTLE GROUP

For over 25 years, The Brattle Group's electricity & energy practice has been a premier provider of energy consulting services. Their consultants answer complex economic, finance, and regulatory questions for electric sector entities, including regulated utilities, system operators, ISO/RTOs, market participants, policy advocates, regulatory commissions and their staff, corporations, law firms, and governments around the world. Furthermore, their experts have testified before federal and state regulatory agencies, courts, and arbitration panels worldwide on complex industry matters.

Their consultants are distinguished by the clarity of insights and the credibility of their experts, which include leading international academics and industry specialists.

III. BRATTLE REPORT SUMMARY

The Brattle Group Report identifies three key drivers underpinning the Companies' proposed resource strategy: (1) the expectation of significant data center load growth, (2) assumptions regarding resource capacity contributions and their impact on reserve margins, and (3) the broader implications of technology assumptions on resource adequacy and resource assessment results. The Report also identifies several key observations related to the Companies' IRP modeling assumptions and resource projections:

(1) Load growth is highly dependent on the likelihood of data centers locating in Kentucky.

(2) The Companies' Planning Reserve Margin analyses significantly understate the contribution of renewables and overstate that of thermal resources.

(3) The Companies' modeling decisions directly limit the addition of solar resources.

(4) The Companies model wind resources as energy-only facilities, discounting entirely the capacity contribution of wind resources in resource adequacy and resource expansion modeling.

(5) The Companies assumptions unfairly favor natural gas generation technologies over a mix of renewable energy and battery storage.

(6) The Companies fail to consider market purchases for low-cost energy throughout the entire study window.

To improve the IRP Analysis and Resource Plan, the Report offers the following seven recommendations for the Commission and the Companies to consider, which are more fully developed in the Report:

Recommendation #1: Develop robust and transparent processes for projecting large load growth development in the Companies' service territories, fully considering the potential load flexibility provisions (via customer-sited backup generation or managed load) that data centers may be able to provide. Consider that the customers who develop and own data centers often have aggressive company clean energy goals and thus delineate certain preferences to the resource types and mix that data center loads must be served with, which are overwhelmingly non-carbon emitting generation in the longer-term.

Recommendation #2: Model additional sensitivity cases that include (1) non-zero solar capacity contributions in the winter, (2) non-zero wind capacity contributions in both summer and winter, (3) an appropriate derating factor to the assumed 100 percent capacity contributions of "fully dispatchable" thermal resources, and (4) coincident forced outages on thermal facilities during extreme winter weather events.

Recommendation #3: Issue competitive solicitation requests for proposals of renewable energy and energy storage systems to test market assumptions and implement IRP plans.

Recommendation #4: Enable greater opportunities for customers to enable zero-emissions generation beyond the Green Tariff Option #3.

Recommendation #5: Consider the value of leveraging market purchases via imports and quantify the realistic cost savings and resiliency benefits that could be provided by imports from neighboring regions.

Recommendation #6: Consider the full scope of the economic value of resources beyond just the resource adequacy value.

Recommendation #7: Integrate improved, proactive local and regional transmission planning to (1) improve access to low-cost capacity and energy purchases that reduce expensive overbuilding of resources within the service territories; (2) improve reliability by leveraging geographic diversity benefits through greater access to neighboring regions, and (3) to perform holistic planning across generation and transmission to develop cost-effective fully integrated generation and transmission plans.

IV. THE COMPANIES' FEBRUARY 28, 2025 CPCN APPLICATION

SREA notes that the Companies applied to the Commission for Certificates of Public Convenience and Necessity ("CPCN") to construct a 400 MW battery energy storage system facility, two natural gas-fired combined cycle ("NGCC") units, and a selective catalytic reduction facility at an existing coal-fired generation plant on February 28, 2025.[2] SREA recommends that the Commission and the Companies should first review and incorporate the recommendations presented here in an effort to more rigorously review the validity of the need for the NGCC proposed in this CPCN.

[2] Case No. 2025-00045, *Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*.

<u>Notice Concerning Confidential Information</u>

SREA provides notice that its Comments and reports do not include information for which the Companies have, by motions, sought confidential protection and is therefore, per 807 KAR 5:001, Section 13(4), accorded confidential treatment pending action by the Commission.

WHEREFORE, SREA respectfully submits its Written Comments.

Respectfully submitted,

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Notice And Certification For Filing

Undersigned counsel provides notice that the electronic version of these comments has been submitted to the Commission by uploading it using the Commission's E-Filing System on this 7th day of March 2025. Pursuant to the Commission's Order in Case No. 2020-00085, *Electronic Emergency Docket Related to Novel Coronavirus Covid-19*, the paper, in paper medium, is not required to be filed.

/s/ David E. Spenard

Notice Concerning Service

The Commission has not yet excused any party from electronic filing procedures for this case.

/s/ David E. Spenard

Comments on LG&E/KU 2024 Joint Integrated Resource Plan (IRP)

KENTUCKY PUBLIC SERVICE COMMISSION CASE NO. 2024-00326

PREPARED BY
Akarsh Sheilendranath
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PREPARED FOR
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MARCH 7, 2025

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NOTICE

- This report was prepared for the Southern Renewable Energy Association in accordance with The Brattle Group's engagement terms and is intended to be read and used as a whole and not in parts.
- The comments and recommendations noted in the Report are based on independent research and publicly available material. They reflect the analyses, views and opinions of the authors and do not necessarily reflect or represent those of The Brattle Group's clients or other consultants.
- Neither The Brattle Group nor the authors accept any responsibility for liability or damages, if any, suffered by any party as a result of decisions made, or not made, or actions taken, or not taken, based on the analysis and/or recommendations included in this Report.

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I. Summary of Comments and Recommendations

The Brattle Group, Inc. was engaged by the Southern Renewable Energy Association to review the 2024 Joint Integrated Resource Plan ("IRP") of the Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU"; "the Companies") and to provide comments and solution-oriented recommendations on the Companies' IRP. In evaluating LG&E/KU's IRP, we have identified three key drivers underpinning their proposed resource strategy: (1) the expectation of significant data center load growth, (2) assumptions regarding resource capacity contributions and their impact on reserve margins, and (3) the broader implications of technology assumptions on resource adequacy and resource assessment results. Our comments discuss these three fundamental considerations and their implications on the Companies' Recommended Resource Plan.

Based on LG&E/KU's study results, it is evident that projected data center load growth is the primary driver of the projected need for capacity expansion. Under LGE/KU's projected low-load scenario—wherein data center loads do not materialize, and energy efficiency measures are more pronounced, the Companies' analysis projects little to no need for new capacity through 2039. While, under the Companies' moderate load projections, which are primarily driven by the Company's data center growth assumptions, new resource development becomes necessary. Notably, without the assumed approximately 1,000 MW of data center load materializing, the Companies would not require a substantial portion of the proposed new resources. Importantly, even if such large load growth were to materialize as projected, the Companies' analysis does not identify the appropriate cost-optimal resource portfolio necessary to serve projected demand and meet resource adequacy or generation reliability requirements that the Companies must plan for. This is because the Companies' analysis undervalues the contributions of renewable energy resources during expected reliability events, while significantly overstating the reliability of dispatchable gas resources. The analysis also does not adequately assess and consider the potential for leveraging imports from neighboring regions during times of need. This misrepresentation of resource contributions toward resource adequacy and undervaluing capacity purchases and trade dynamics with neighboring regions, coupled with unsubstantiated large load projections, raises concerns about the validity of the IRP's assumptions, the cost-effectiveness of the solutions rendered, and the balance of its proposed resource mix. A more comprehensive and risk-adjusted approach is necessary to ensure that the resource planning process reflects a realistic and resilient strategy for meeting future energy demands. Toward this effort, we offer the following recommendations related to the IRP:

- **Recommendation #1:** Develop robust and transparent processes for projecting large load growth development in the Companies' service territories, fully considering the potential load flexibility provisions (via customer-sited backup generation or managed load) that data centers may be able to provide. Consider that the customers who develop and own data centers often have aggressive company clean energy goals and thus delineate certain preferences to the resource types and mix that data center loads must be served with, which are overwhelmingly non-carbon emitting generation in the longer-term.
- **Recommendation #2:** Model additional sensitivity cases that include (1) non-zero solar capacity contributions in the winter, (2) non-zero wind capacity contributions in both summer and winter, (3) an appropriate derating factor to the assumed 100 percent capacity contributions of "fully dispatchable" thermal resources, and (4) coincident forced outages on thermal facilities during extreme winter weather events.
- **Recommendation #3:** Issue competitive solicitation requests for proposals of renewable energy and energy storage systems to test market assumptions and implement IRP plans.
- **Recommendation #4**: Enable greater opportunities for customers to enable zero-emissions generation beyond the Green Tariff Option #3.
- **Recommendation #5**: Consider the value of leveraging market purchases via imports and quantify the realistic cost savings and resiliency benefits that could be provided by imports from neighboring regions.
- **Recommendation #6**: Consider the full scope of the economic value of resources beyond just the resource adequacy value.
- **Recommendation #7**: Integrate improved, proactive local and regional transmission planning to (1) improve access to low-cost capacity and energy purchases that reduce expensive overbuilding of resources within the service territories; (2) improve reliability by leveraging geographic diversity benefits through greater access to neighboring regions, and (3) to perform holistic planning across generation and transmission to develop cost-effective fully integrated generation and transmission plans.

The remainder of our comments include a summary of relevant IRP results, key issues with IRP resource and modeling assumptions, and strategic recommendations to assist LG&E/KU with their goal to "[d]evelop a resource plan that will enable the Companies to serve all customers safely, reliably, and at the lowest reasonable cost at all times, day or night, and in all seasons and weather conditions."[1]

II. IRP Summary

To achieve the aforementioned goal, the Companies forecast their expected load over a 15-year planning horizon (**electric sales and demand forecast**), determine the minimum summer and winter reserve margins they require to maintain a loss of load expectation (LOLE) of one day in every ten years (1-in-10) (**resource adequacy analysis**), and model the generation resource mix necessary to meet minimum reserve margins (**resource assessment**).

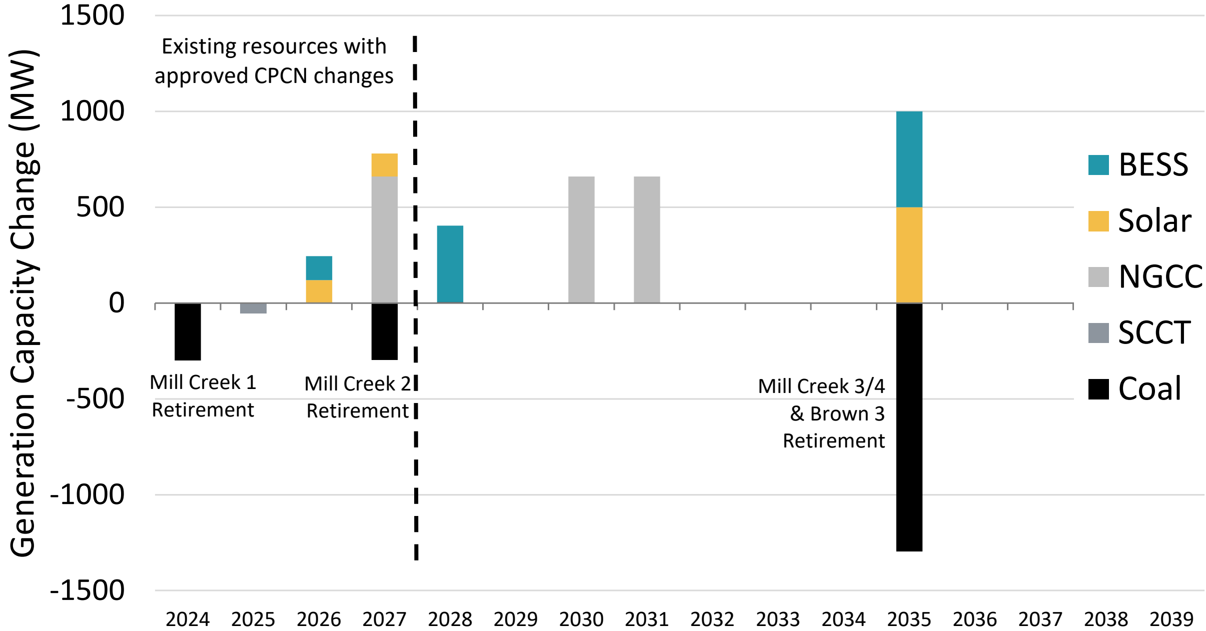
The Companies modeled 60 potential future capacity expansion scenarios based on three load scenarios (Low, Mid, High), four environmental regulatory scenarios (No new regulation, Ozone NAAQS, Ozone NAAQS + ELG, Ozone NAAQS + ELG + GHG), and five fuel price scenarios.[2] The Companies decided that Mid load growth and the implementation of Ozone NAAQS and ELG regulations is the most likely scenario to occur. Additionally, a Solar Cost Sensitivity case was run for these conditions in which solar costs escalated from the beginning of the analysis period (for a total of 65 scenarios analyzed). The Companies selected the case in which solar costs increased the entire study window to be the most likely scenario.

Based on these constraints (Mid load growth, Ozone NAAQS + ELG, and Solar Cost Sensitivity), production cost models were run across all five fuel scenarios and the lowest average present value revenue requirement (PVRR) was selected. While developing the Recommended Resource Plan, the Companies considered a resource portfolio that is a "no regrets" plan if higher load were to materialize or CO_2 regulations do not remain. Figure 1, below, shows the resource changes based on the Companies' Recommended Resource Plan.

[1] IRP Volume I, Plan Summary, Section 5.(1).(b) ("Planning Objectives"), pp. 5-3 [PDF 10 of 135].

[2] IRP Volume III, Resource Assessment, Section 4.4 ("Stage One: Assessing Load and Environmental Regulation Uncertainty"), [PDF 93 of 259].

FIGURE 1. LG&E/KU RECOMMENDED RESOURCE PLAN CHANGES



III. Key Issues related to IRP Modeling Assumptions and Resource Projections

1. **Load growth is highly dependent on the likelihood of data centers locating in Kentucky**.

The differences in the three load growth scenarios modeled by the Companies ("Low," "Mid," and "High") are highly contingent on the expected economic development activity within the Companies' footprint. Economic development projects include large industrial loads and new data centers. The Companies estimate that in both the Mid and High growth scenarios, all data center load would online by 2032. Consequently, from 2032 through 2039, summer and winter peak demand forecasts remain relatively constant.

Data centers that locate within LG&E/KU territories are expected to be the primary driver of load growth over the time horizon of the study. These large loads are expected to be constant, with load factors in the range of 95%, and account for most of the growth on the system.[3] In fact, data center load is expected to account for 74% or more of the peak load growth in the Mid or High load scenarios compared to the Low load scenario. Table 1, below, shows the percentage of peak load attributable to data centers in the Mid and High load scenarios. In the

[3] IRP Volume I, Plan Summary, Section 5.(3) ("Energy Requirements ('Load') Forecasts"), pp. 5-13 [PDF 20 of 135].

Low load scenario, where there is no additional economic development and two large load customers are lost, winter and summer peak demands are forecasted to decrease slightly. While the Low and High load scenarios represent the boundary conditions of forecasted changes, it is evident that the need for, and timing of, additional generation resources is dependent on if (and if so, when) data centers come online in the system.

TABLE 1. AMOUNT OF PEAK LOAD (MW) IN 2032 ATTRIBUTABLE TO DATA CENTERS

Season (2032)	Low Load Scenario	Mid Load Scenario			High Load Scenario		
	Peak (MW) [1]	Peak (MW) [1]	Change from Low Scenario [2]	Data Center % of Growth [3]	Peak (MW) [1]	Change from Low Scenario [2]	Data Center % of Growth [3]
Summer	5844	7201	1357	77%	8218	2373	74%
Winter	5876	7135	1259	83%	8142	2265	77%

Sources and Notes:

[1]: Data from IRP Workpapers: '20241001 Resource Assessment RM Need Tables_D02.xlsx'

[2]: Change in Peak MW from Low Load Scenario

[3]: Data centers account for 1050 MW in the Mid Load Scenario and 1750 MW in the High Load Scenario; Calculated as data center load divided by change in load from Low Load Scenario.

As of January 2025, the Companies have only one data center project that is in the "imminent" phase, which indicates a high probability for the project to announce and locate in the service territories, representing 0.4 GW of potential load.[4] There are 17 other projects that are in various stages ranging from "inquires" to "prospects," as defined by the Companies, representing an additional 5.8 GW of potential load. The Companies build their Recommended Resource Plan upon the premise of over 1 GW of this potential load materializing; however, beyond the announcement of plans for a large-scale data center in Louisville to be operational by late 2026,[5] this load growth is speculative and relies on additional data centers choosing to locate in Kentucky. Historically, data centers have concentrated in areas near high population centers and electricity prices and local laws are favorable. While Kentucky recently passed a law that allows data centers that invest a minimum of $450,000,000 within Louisville city limits to avoid paying sales and related taxes for 50 years, this does not guarantee that several data centers amounting to over 1 GW of load will locate within the Companies' territories.[6]

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[4] See SC DR2-13.

[5] Green, Marcus, "Developers unveil plans for large tech data center in Louisville, the 1st of its kind in Kentucky," January 16, 2025, WDRB. https://www.wdrb.com/in-depth/developers-unveil-plans-for-large-tech-data-center-in-louisville-the-1st-of-its-kind/article_e7adef68-c92f-11ef-b262-bf1780db36c6.html

[6] See Kentucky House Bill 8 (2024 Legislative Session). https://legiscan.com/KY/text/HB8/2024. Additionally, note that both sources cited in the IRP do not include Kentucky as key U.S. data center markets (Newmark, EPRI 2024 Powering Intelligence).

Additionally, this incentive does not apply to data centers that benefit from the sales and use tax related to commercial mining of cryptocurrency, which SPP postulates could be a potential use case of data centers electing to locate away from population centers.[7]

Beyond locating where local laws incentivize, many of the current data center developers have company clean energy goals and are rapidly contracting renewable energy sources to meet the growing demand.[8] The Companies even acknowledge that "growth in data center load is driven significantly by customers with aggressive carbon goals."[9] The Companies assert that it is unknown if the data center projects will participate in Green Tariffs, demand response, or rely on behind-the-meter resources based on their conversations with potential customers.[10] However, they simply remedy this uncertainty in demand for clean energy generation by including the "Enhanced Solar Resource Plan" that maintains the same resource additions as the Recommended Resource Plan and adds 1 GW of additional solar through 2032. They consider this solar to be added under the Green Tariff Option #3, but they do not provide the modeling to support including this amount of solar and instead simply add the 1000 MW in increments to match the load growth expectations.

Despite the lack of definitive commitments from multiple data centers, the Companies' resource adequacy and expansion planning assume that several of these facilities will materialize within the service territories. This reliance on speculative load growth could present risks if anticipated developments fail to materialize as projected. A more robust planning approach would incorporate greater sensitivity analyses to account for potential variability in data center growth and explore the potential for load flexibility for those that do locate in the service territories, as discussed below in our recommendations.

2. The Companies' Planning Reserve Margin analyses significantly understate the contribution of renewables and overstate that of thermal resources.

To develop winter and summer planning reserve margin assumptions for their resource plan, the Companies employed the loss-of-load expectation ("LOLE") methodology. Specifically, the Companies calculated the reserve margins necessary to achieve a one day in 10 years ("1-in-

[7] See SPP Future Load Scenarios at pp. 15.

[8] Wilson, Adam, "Datacenter companies continue renewable buying spree, surpassing 40 GW in US," S&P Global Market Intelligence (2023). https://www.spglobal.com/market-intelligence/en/news-insights/research/datacenter-companies-continue-renewable-buying-spree-surpassing-40-gw-in-us.

[9] IRP Volume III, Resource Assessment, Section 1.3 ("Companies' Planning Process Is Comprehensive"), [PDF 71 of 259].

[10] See response to SC DR1-12(e).

10") LOLE standard.[11] Based on projected load growth by 2032 (when all data center load growth is assumed to be online), the Companies modeled 51 load scenarios (one for each of the previous 51 years of hourly weather data) and 300 unit availability scenarios for a total of 15,300 cases.[12] The resulting winter reserve margin is set at 29% and the summer reserve margin is set at 23%.

The Companies calculate the reserve margins using the counterfactual resource portfolio that would exist if there were no additional changes to their generating resources beyond those in the approved 2022 CPCN. In evaluating this portfolio, the Companies assign seasonal capacity contributions only to renewable resources. Fully dispatchable[13] and limited-duration resources are assigned flat capacity contributions throughout the year. Table 2, below, displays the capacity contributions that are applied to each generating resource type in the IRP modeling.

TABLE 2. CAPACITY CONTRIBUTIONS OF GENERATION RESOURCES

Generation Resource	Capacity Contribution *Summer*	*Winter*
Fully Dispatchable	100%	100%
Limited-Duration		
4-hr BESS	85%	85%
8-hr BESS	93%	93%
Renewables		
Solar	84%	0%
Wind	0%	0%

Despite historical evidence indicating that fully dispatchable units are also subject to availability constraints[14], and recent evidence identifying heightened weather-correlated outage risks of natural gas and coal facilities even in organized markets, including in PJM which administers regional markets in parts of Kentucky, the Companies assumed that thermal resources would be fully available at seasonally rated capacities across all projected seasonal peak conditions. While the Companies appear to acknowledge that their fully dispatchable resources do

11 IRP Volume III, Resource Adequacy Analysis, Section 3 ("Reserve Margin Constraints for Resource Planning"), pp. 11 [PDF 45 of 259].

12 IRP Volume III, Resource Adequacy Analysis, Section 2 ("Introduction"), [PDF 42 of 259].

13 Fully dispatchable resources refer to natural gas simple-cycle combustion turbines (SCCTs), natural gas combined-cycle (NGCC), and nuclear generation technologies.

14 In Table 14 of the Resource Adequacy Analysis, the Companies indicate that annual median historical EFORs for their existing coal and SCCTs ranged from 2.7% to 9.1% from 2009 to 2024.

experience unplanned outages—by modeling the units' equivalent forced outage rate ("EFOR") in their reserve margin estimation analysis—they ignore these average EFORs, and instead assume 100% capacity contribution from such facilities in their capacity expansion analysis to project their future resource needs. More importantly, the Companies do not capture the potential coincident outages in their thermal, fully dispatchable facilities that can occur at much higher probabilities during extreme weather than during other times. The Companies claim that they have considered the potential for coincident outages during extreme winter weather events and that there is "no correlation between forced outages and cold temperatures (i.e., less than 20 degrees Fahrenheit)."[15] However, despite LG&E/KU's winter resource assessment asserting that the Companies could handle their projected winter peak demand, the weather during Winter Storm Elliott caused forced derates due to cold temperatures and mechanical issues, as well as fuel disruptions further increasing generation reduction.[16]

The Companies acknowledge that winter weather variability is significant. Over the last 50 years, the median low temperature was 4 degrees Fahrenheit; however, it is not uncommon for temperatures to be below zero, including down to 20 degrees below Fahrenheit.[17] Our analysis of forced outage rates of thermal facilities operating in the neighboring PJM region between 2012 and 2022 (provided by PJM), show that natural gas-fired and other thermal facilities experienced high forced outage rates at cold temperatures.[18] Figure 2, which illustrates historical forced outage rates of gas SCCTs operating in PJM, show that at temperatures below approximately 25 degrees Fahrenheit, the unit forced outage rates increase rapidly. And at temperatures below zero-degree Fahrenheit, the forced outage rates average 20 percent, ranging as high as 60 percent. This means that during cold winter conditions, including winter peaks and/or extreme cold snaps during [add years], on average, only 40 to 70 percent of PJM's gas SCCT fleet was operational due to high temperature correlated forced outage rates. This poses a major resource adequacy risk to power systems—as PJM and other regional transmission organizations ("RTOs") have determined, overhauling recently their resource adequacy and capacity contribution assessment methodologies to better reflect resource adequacy challenges and how various resources perform during such challenging conditions.

[15] SREA DR2-6, LG&E/KU Response.

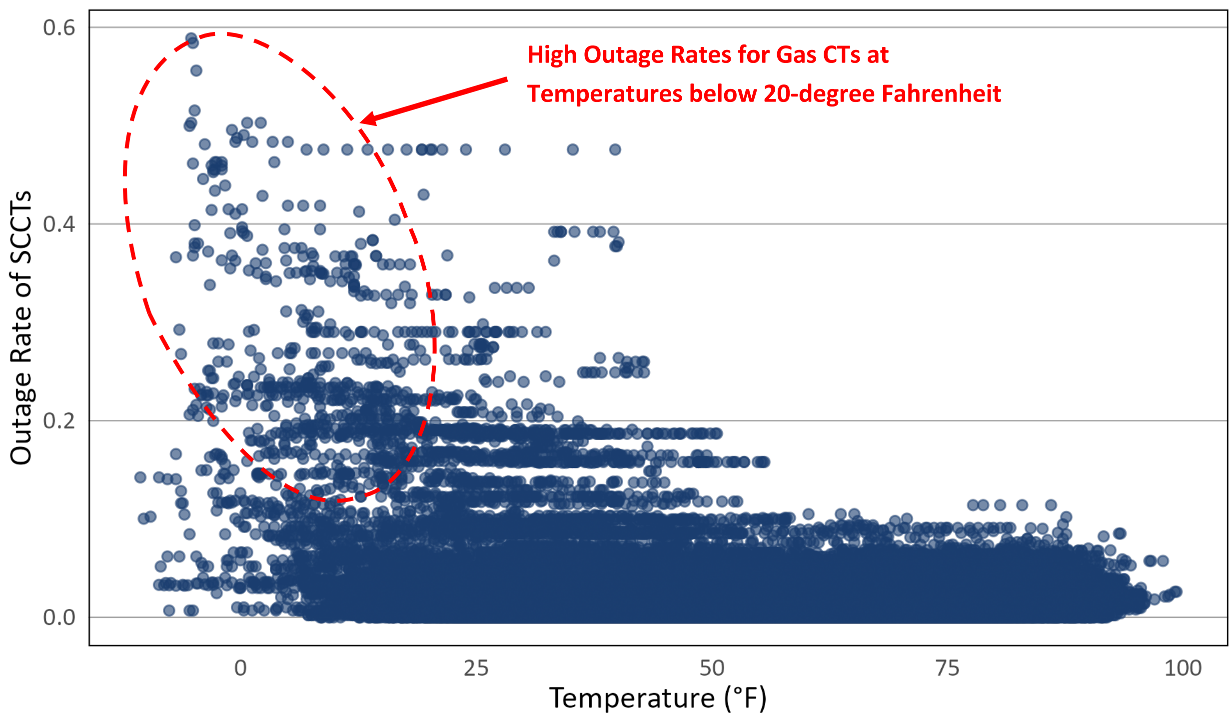
[16] FERC, "Inquiry into Bulk-Power System Operations during December 2022 Winter Storm Elliott," (2023) pp. 47 [PDF 47 of 167].

[17] IRP Volume III, Resource Adequacy Analysis, Section 2 ("Introduction"), pp. 6 [PDF 40 of 259].

[18] Weather data from: Open-Meteo (https://open-meteo.com/) for 39.47N and 78.92W. PJM historical forced outage data from 2026-2027 Unlimited Classes Hourly Time Series Forced Outage data, available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-2027-unlimited-classes-hourly-time-series-forced-outage.xlsx.

Notably, in the neighboring PJM region, over 70 percent of resource adequacy challenges are expected to manifest in winter, despite PJM remaining a summer peaking system in the near term. This is because, winter resource adequacy risks are not only a function of winter peak load levels. Rather, it accounts for very high forced outage rates of thermal facilities and low (albeit non-zero) contributions of solar generation. LGE/KU's thermal facilities are not immune to such weather-correlated outage risks, and the Companies have entirely failed to consider this important risk in their IRP analysis.

FIGURE 2. ALL OUTAGE RATES FOR SCCTS AS A FUNCTION OF TEMPERATURE IN PJM (2012 TO 2022)



Source: PJM Historical Forced Outage Data and Open-Meteo. See footnote 19.

The limited application of seasonal adjustments and potential underestimation of forced outage impacts on fully dispatchable resources indicate that the IRP's reliability estimates are more optimistic than actual system performance may be during extreme events in the future.

Beyond the application of seasonal capacity contributions only to renewables, the Companies decided to calculate the winter and summer reserve margins without including the 758 MW of solar resources that are planned to be online by 2032. The exclusion of this planned solar capacity leads to inflated winter reserve margins. When solar resources are included in the SERVM modeling, they do not contribute to the winter reserve margin as the Companies assign a zero percent capacity contribution to solar (and wind) during the winter, as discussed further below. However, in summer, where solar generation is allowed to contribute meaningfully to peak demand hours, the exclusion of these 758 MWs artificially lowers the summer reserve margin. Specifically, looking at 2032 peak load conditions with the planned resource mix, the Companies report a summer reserve margin of 13.2% without solar and 22% with solar. The Companies justify their decision to exclude solar by stating that it shifts reliability risk to the winter, even as the annual LOLE remains at 1.0, which meets their predefined standard. This exclusion suggests an overly conservative approach that does not fully account for the full value of resources that are planned and approved to be operating on the system in the study year. When the Companies do account for all available resources by modeling the system with the 758 MW of solar, the required winter reserve margin decreases from 29% to 23%, indicating that these solar facilities would contribute some capacity during winter needs.

Finally, the Companies fail to consider the full value of imports during extreme weather events in calculating their reserve margins requirements, as well as in their capacity expansion analysis. While the Companies acknowledge the potential for imports from neighboring regions (MISO, PJM, and TVA), their baseline reserve margin study does not incorporate these external resources adequately. The Companies state that they are uncertain in their ability to rely on neighboring regions to serve load. They note that "[a]pproximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years."[19] However, this assumption does not account for the vast resources that have come *online* in parallel with these retirements, nor does it account for geographic diversity in gross load and net load patterns, or in weather patterns across the Companies' service territories and its neighboring regions. Instead, the Companies assume minimal reliance on imports—as though they were an islanded system—leading to higher internal capacity requirements to meet projected needs in the service area. When the Companies consider a sensitivity case where available transmission capacity (ATC) is considered (at a value of 700 MW), the annual LOLE drops significantly from 1.0 to 0.15.[20] Additionally, the Companies transfer study results indicate that there is significant capacity available to facilitate long-term transfers (especially in the winter months, when resource adequacy challenges are likely to be the greatest).[21]

The Companies also claim, without any substantiating evidence, that the "ability to purchase power from neighboring regions often depends entirely on the availability of transmission

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[19] IRP Volume III, Resource Adequacy Analysis, Section 5.2 ("Neighboring Regions"), pp. 20 [PDF 54 of 259].

[20] IRP Volume III, Resource Adequacy Analysis, Section 3.1 ("Sensitivity Analysis"), Table 9: Sensitivity Analysis (Least-Cost Generation Portfolio) [PDF 51 of 259].

[21] IRP Volume III, Long-Term Firm Transfer Analysis – Impact to the LG&E/KU Transmission System, Study Results [PDF 256 – 258 of 259].

capacity."[22] If limited transmission capability were the key constraint in accessing out-of-footprint capacity and energy purchases, then the Companies' stated concern about uncertainty in their ability to rely on neighboring regions to serve load due to recent retirements in PJM appears to be misplaced. If accessing market purchases from across Southeast BAs is limited by transmission, it indicates that a coordinated and proactive interregional transmission planning, as well as integrated transmission and resource planning, would be very valuable in unlocking greater value for customers and more cost-effectively meeting projected demand and resource adequacy needs in the Companies' service areas.

3. The Companies' modeling decisions directly limit the addition of solar resources.

The Companies' modeling decisions directly restrict the addition of solar resources, despite solar being cost-competitive relative to other technology options. A significant limitation is the assignment of a zero percent capacity contribution of solar during winter months. The inability of solar to contribute to the Companies' winter peak is propagated throughout the resource adequacy analysis and the resource assessment (i.e., capacity expansion modeling). In doing so, the Companies make it impossible for solar resources to contribute to the winter reserve margin and, therefore, the models would not select solar no matter the cost differential from other fully dispatchable resources.

The Companies claim that "winter peaks typically occur in the mornings or evenings during non-daylight hours."[23] Subsequently, they claim that solar has no possibility of contributing to winter peak demand hours. While solar resources typically contribute much less during winter peak hours than summer peak hours, it is still common in other jurisdictions to assign solar a non-zero capacity contribution. (See Table 3)

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22 IRP Volume III, Resource Adequacy Assessment, Section 5.3 ("Load Modeling"), [PDF 55 of 259].

23 IRP Volume I, Plan Summary, Section 5.(1).(b) ("Planning Objectives"), pp. 5-4 [PDF 11 of 135].

TABLE 3. COMPARISON OF SOLAR RESOURCE CAPACITY CONTRIBUTIONS ACROSS REGION

Region/Utility		Summer	Fall	Winter	Spring	All Year
LG&E/KU, KY Solar	[1]	84%	0%	0%	0%	
TVA	[2]	68%		15%		
Georgia Power	[3]	25% - 35%	25% - 35%	5-10%	25% - 35%	
Duke Kentucky	[4]					9%
Duke Indiana, 2025	[5]	24.2%		13.4%		
Duke Indiana, 2035	[6]	11.7%		1.2%		
PJM	[7]					11%
MISO	[8]	50%	50%	5%	50%	

Sources:
[1]: LGEKU 2024 IRP
[2]: Georgia Power, 2022 IRP Effective Load Carrying Capability ("ELCC") Study
[3]: TVA, Integrated Resource Plan 2025, Volume 1 (Draft)
[4]: Duke Kentucky, 2024 IRP, Table 4.2. Based on PJM's 2025/26 BRA ELCC Class Ratings.
[5]-[6]: Duke Indiana, 2024 IRP, Appendix C.
[7]: PJM, ELCC Class Ratings for the 2026/2027 Base Residual Auction
[8]: MISO, Planning Year 2024-2025 Wind and Solar Capacity Credit Report

The Companies justify their decision to assign a zero percent capacity contribution to solar by reviewing historical data on when winter peak loads occurred (most commonly in the hour beginning 7 AM) and obtaining the median solar generation at 10 sites across Kentucky at that time. As noted previously, the timing of winter peaks themselves does not necessarily coincide with winter *risks.* Resource adequacy risks are more likely to manifest during high *net* load ("net peak") hours, and when conventional generating resources are contemporaneously experiencing high forced outage rates due to extreme temperatures and tightness in gas supply for heating loads. Without weatherizing power plants, gas supply infrastructure, and/or procuring on-site back-up fuel in advance of winter risk events, temperature correlated unit outage risks would remain high during winter conditions. These conditions, together with high winter net load, contribute to winter resource adequacy risks. Solar facilities tend to contribute at non-zero capacity values during such winter risk events, as evidenced by more rigorous analysis performed by PJM and MISO that accredit solar contributions at 5% or higher.

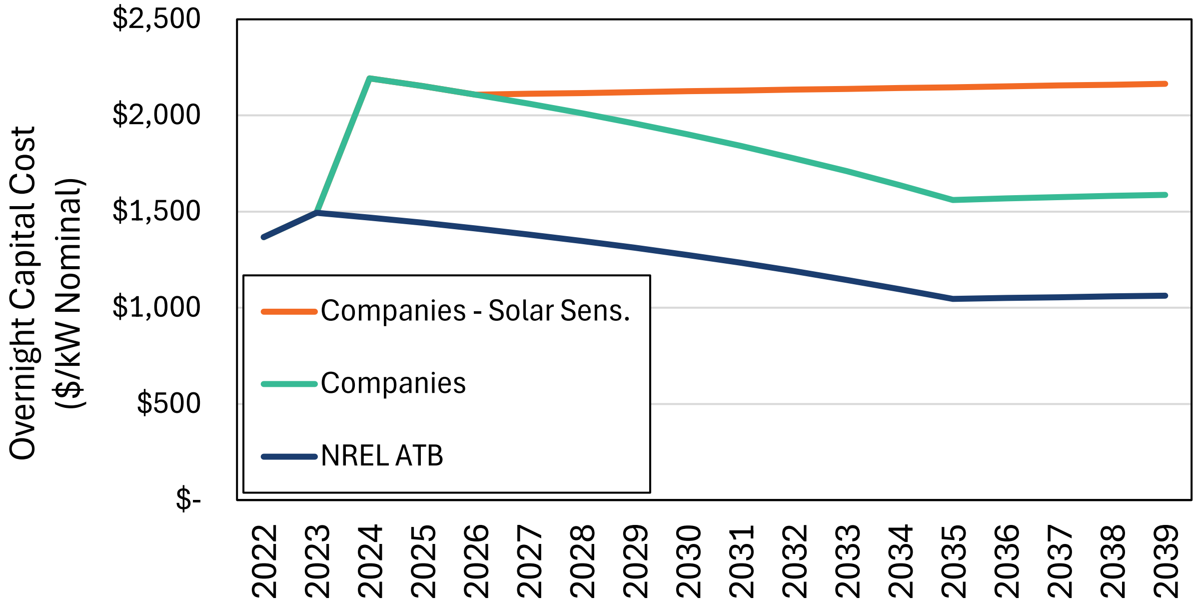
In addition to limiting solar's capacity contribution, the Companies take a conservative approach to solar cost projections, further constraining its role in long-term planning. the Companies use a single data point (the Mercer County Solar project) to benchmark expected costs for utility-scale solar resources. While it is useful to use a solar installation project within one of their territories, using a single data point does not necessarily constitute a realistic expectation of solar costs in other parts of the service territories (i.e., one data point does not create a trend). It is common practice to benchmark the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") estimates to match local costs; however, the

Companies did not look to other recent solar installation costs in neighboring jurisdictions to determine a range of values that could be assumed as more reasonable cost benchmarks. By only using the Mercer County Solar project as the benchmark price, the Companies apply a 49% increase to the baseline NREL ATB cost estimates for overnight capital costs. To have informed price discovery on realistic solar costs the Companies should issue Requests for Proposals ("RFPs") for market bids for solar, wind, and storage Power Purchase Agreements ("PPAs") and Purchase Sale Agreements ("PSAs") that can inform the market costs for such facilities.

Additionally, in the Companies' modeling of the scenario that the Companies deem likely-to-occur (Mid load, Ozone NAAQS + ELG), the results showed that it would be cost-effective (i.e., least cost) for Ghent Unit 2 to enter non-attainment status and instead to add new solar facilities to the system. However, the Companies appear to question the underlying assumptions they used in this analysis by employing NREL's ATB forecast of declining solar costs. They refute NREL's solar cost decline projection through 2035 based on "the significant increases in the costs of solar projects [they] have observed over the past several years, these declines are particularly uncertain."[24] Yet, they employ the 2024 NREL ATB mid-level estimates to determine cost trends for all other resources considered in their IRP. For solar costs, the Companies replace NREL cost trend projection with their own conjectured "Solar Cost Sensitivity." This sensitivity case is predicated, without any substantiation, on the assumption that utility-scale solar overnight capital costs ($/kW) will never decrease during the study window and instead increase at a rate of 0.2% per year starting in 2025. This compares with NREL ATB's cost estimates for solar that decrease by nearly 30% through 2035 and then increase by 0.2% on average (in nominal terms) through the rest of the study window. Figure 3, below, illustrates that difference between the NREL ATB overnight capital cost estimates against the Companies baseline and unsubstantiated "Solar Cost Sensitivity" growth rates.

[24] IRP Volume III, Resource Assessment, Section 4.4.1.3 ("Ozone NAAQS + ELG Environmental Scenario"), pp. 34 [PDF 98 of 259].

FIGURE 3. COMPARISON OF SOLAR OVERNIGHT CAPITAL COST ASSUMPTIONS (NOMINAL)



4. **The Companies model wind resources as energy-only facilities, discounting entirely the capacity contribution of wind resources in resource adequacy and resource expansion modeling.**

In addition to solar, the Companies' modeling approach significantly limits the capacity contribution and economic value of wind resources, treating the resources strictly as energy-only resources without integrating them into resource adequacy or expansion planning. Although wind is considered as a viable technology in the planning process and has high capacity contribution (approx. 35 percent) in winter, wind is assigned a zero percent contribution to both winter and summer peaks, effectively disregarding its potential resource adequacy benefits. This approach diverges from neighboring regions, which assign nonzero capacity credits to wind, recognizing that while intermittent, wind generation does provide some contribution to peak reliability, and especially high-capacity contribution during winter when resource adequacy risks are expected to be the greatest in LGE/KU's service area. The Companies' decision to exclude wind from reserve margin calculations artificially suppresses its role in capacity planning, yet again favoring fossil-based alternatives despite the growing cost-competitiveness and reliability benefits of wind.

The Companies provide the following reasons for modeling wind as an energy-only resource: [25]

- There is uncertainty in wind's availability during peak hours.
- LG&E/KU has received limited responses in past RFPs.[26]
- There is uncertainty regarding the cost of wind.
- There is no way to estimate transmission system upgrade costs for wind sites that do not currently exist.
- Reliance on generation that must be exported from other transmission areas risks having even firm transmission cut during times of energy emergencies, which is when the Companies would need the resources most.

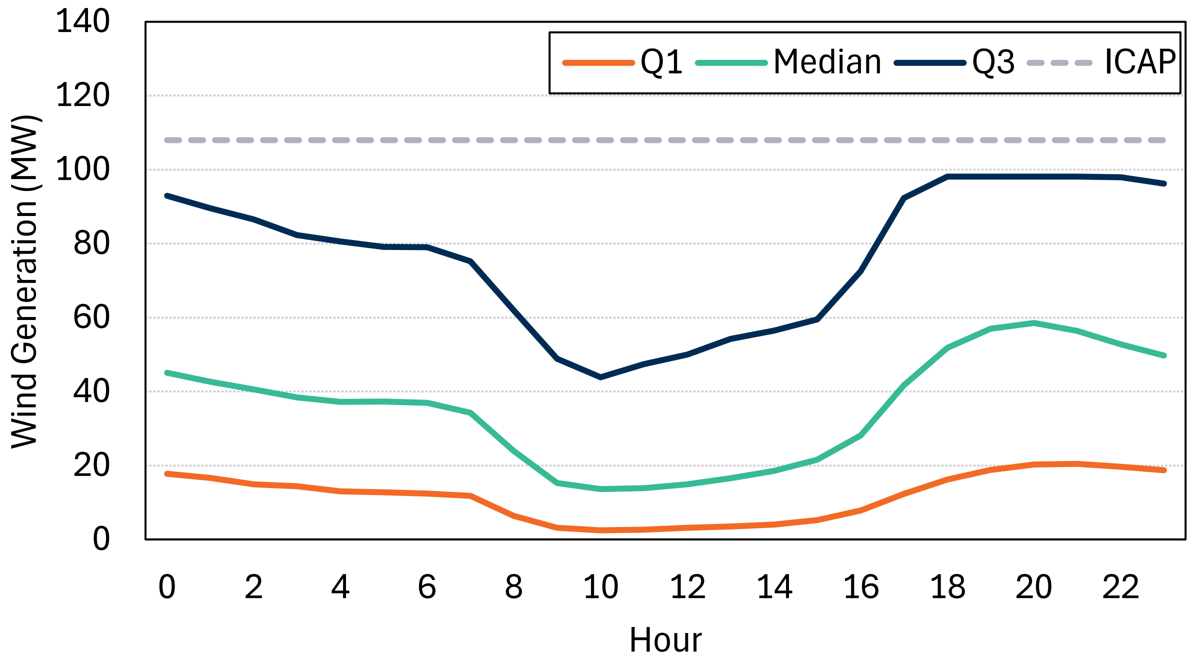
While there may be uncertainty in wind generation during peak hours, it should not preclude the Companies from estimating plausible generation profiles. Wind generation in Kentucky and Indiana is expected to produce at its highest during winter and during the early morning/late evening hours, when the needs of the system are expected to be most pressing. In fact, the Companies performed an analysis of wind generation profiles in their Resource Assessment using data from the NREL's System Advisor Model ("SAM"). In their IRP workpapers, the Companies modeled a 108 MW wind generation site in Union, KY.[27] Based on their own findings, the winter generation profile for wind indicates output between 30% to 40% of installed capacity (ICAP) during winter peak hour(s), as indicated by Figure 4. This is also consistent with PJM's capacity accreditation for wind facilities at 35 percent for delivery year 2026/27.

[25] IRP Volume III, Technology Update, Section 3.2.3 ("Contributions to Winter and Summer Peak Demands"), pp. 20 [PDF 28 of 259].

[26] In 2022, the Companies only received one response for their RFP for out-of-state wind (143 MW). See IRP Volume III, Technology Update, Section 3.2.2 ("Wind"), [PDF 27 of 259].

[27] See IRP Workpaper "gen_output_V150_4.5_100m_108MW.csv"

FIGURE 4. COMPANIES' WINTER WIND GENERATION PROFILE AT SAMPLE LOCATION IN UNION, KY



These findings are consistent with the nonzero capacity contribution assigned to wind in neighboring regions. (See Table 4)

TABLE 4. COMPARISON OF WIND RESOURCE CAPACITY CONTRIBUTIONS ACROSS REGION

Region/Utility		Summer	Fall	Winter	Spring	All Year
LG&E/KU, KY Solar	[1]	0%	0%	0%	0%	
TVA	[2]	19%		33%		
Georgia Power	[3]	40%	40%	50%	40%	
Duke Kentucky	[4]					35%
Duke Indiana, 2025	[5]	15.1%		19.2%		
Duke Indiana, 2035	[6]	8.6%		14.2%		
PJM	[7]					35%
MISO	[8]	18.1%	15.6%	53.1%	18.0%	

Sources:
[1]: LGEKU 2024 IRP
[2]: Georgia Power, 2022 IRP ELCC Study
[3]: TVA, Integrated Resource Plan 2025, Volume 1 (Draft)
[4]: Duke Kentucky, 2024 IRP, Table 4.2. Based on PJM's 2025/26 BRA ELCC Class Ratings.
[5]-[6]: Duke Indiana, 2024 IRP, Appendix C.
[7]: PJM, ELCC Class Ratings for the 2026/2027 Base Residual Auction
[8]: MISO, Planning Year 2024-2025 Wind and Solar Capacity Credit Report

Discounting entirely the capacity contribution of wind resources in resource adequacy and resource expansion modeling yet again leads to a bias toward gas and coal heavy projected portfolios that may not be cost-effective for customers, and for all the reason related to outage risks, may not even address resource adequacy risks effectively.

Additionally, as a result of no commercial-scale wind projects under development in Kentucky, the Companies also assume that they do not have any data to benchmark wind costs against. Instead, they use the NREL ATB estimates and erroneously apply the same 49% increase that they applied to solar costs based on their solar overnight capital cost analysis. Specifically, the Companies state, "In the absence of a recent capital cost estimate for wind, the Companies estimated the capital cost of wind by applying the implied inflation rate for solar to the "Moderate" capital cost estimate for wind in NREL's 2024 ATB."[28]

The Kentucky PSC's Staff recommendations for the 2024 IRP included a directive to "consider resources outside of its service territory with transmission cost based on specific updated analyses of transmission costs."[29] The Companies assert that they are only able to include wind as an energy-only resource in their IRP modeling due to uncertainty about its availability, costs, and reliance on generation exports from other regions; however, their internal modeling shows that wind could be a valuable resource in meeting winter peak demands (especially when solar is unavailable, as they assume). The Companies should conduct transmission assessments to estimate costs and value of accessing wind from wind-rich regions such as Indiana and delivering to the Companies service territories. Such analyses are routinely performed by Load Serving Entities in other wind-rich markets, such as SPP and ERCOT. Additionally, the Companies should issue Requests for Information ("RFIs") and RFPs for wind generation delivered to the service areas from within and outside of Kentucky.

5. The Companies assumptions unfairly favor natural gas generation technologies over a mix of renewable energy and battery storage.

The Companies' modeling assumptions favor NGCC units, overlooking the potential reliability and cost advantages of a diversified portfolio that includes renewables and battery storage. Their approach fails to consider the complementary relationship between solar and storage, in which co-located systems can provide more flexible and cost-effective grid support.[30] In fact, the Companies' own interconnection queue contradicts this approach, as it includes nearly 900

[28] IRP Volume III, Technology Update, Section 4 ("Converting NREL Costs from Real to Nominal Dollars"), pp. 26 [PDF 34 of 259].

[29] See Kentucky PSC Staff Report on LG&E/KU 2021 IRP, [PDF 72 of 75]. https://psc.ky.gov/pscscf/2021%20Cases/2021-00393//20220916_PSC_ORDER.pdf

[30] See SREA DR1-1.

MW of solar-plus-storage projects, compared to only 245 MW of standalone storage and 1,600 MW of solar-only resources. [31] By not integrating these trends into their planning, the Companies artificially limit the viability of renewables and overstate the need for gas-fired generation. It should be notes that co-locating does not necessarily mean a closed system of solar and storage facilities that are configured such that the storage facility is charged exclusively from the co-located solar unit. An open configuration of co-located (at same point of grid interconnection) allows storage to charge and discharge from the gid when solar may not be available. Such as system provides improved resource adequacy performance cost effectively by unlocking the complementary benefits of low-cost solar energy and high resource adequacy value of storage facility.

The Companies use overly simplistic modeling techniques to justify their conclusions about the scale of renewables and storage needed to replace fossil generation. For example, their Excel-based analysis claims that replacing 1 MW of coal generation at Mill Creek 3 would require 8.4 MW of solar and 6.6 MW of battery storage, suggesting that renewables are inherently inefficient as a replacement for baseload power. [32] However, this assumption fails to account for more dynamic system configurations, such as hybrid solar-plus-storage setups optimized for peak demand periods, demand-side management, and diversified renewable inputs that can be charged by any resource on the system. A more sophisticated analysis incorporating real-world dispatch patterns and grid flexibility would likely demonstrate that renewables and storage can provide firm capacity at a much lower scaling ratio than the Companies suggest.

Additionally, the Companies continue to assign a 100% capacity contribution to NGCCs and simple-cycle combustion turbines ("SCCTs") in PLEXOS, without adjusting for real-world seasonal outage risks. As explained previously, this assumption is erroneous and misaligned with industry practices. In the neighboring PJM region, PJM's 2025/26 Base Residual Auction (capacity auction) recognized and applied between 21 to 39 percent reduction in capacity contribution (based on the unit's ELCC) to SCCTs and NGCCs, reflecting the unplanned outages that occurred across the PJM, including in parts of Kentucky during extreme weather events. [33] The Companies claim that because they are not in an RTO, the concept of capacity accreditation does not apply to them.[34] This is misguided. The reliability value or the resource adequacy value

[31] Based on LGE/KU interconnection queue data as of February 5, 2025. Retrieved from https://www.oasis.oati.com/LGEE/index.html

[32] Page 13, LGEKU Technology Update, 2024 IRP Volume III.

[33] IRP Volume III, RTO Membership Analysis, Section 4 ("CIFP Market Reform Impacts to Accredited Capacity"), pp. 13 [PDF 147 of 259], and PJM's ELCC Class Ratings for the 2025/2026 Base Residual Auction.

[34] See PSC DR2-3.

that a resource provides to the system has no bearing on whether such resource operates within the confines of an organized independent system operator ("ISO") or RTO market or within a balancing area that does not administer a market for procuring capacity. The resource adequacy value of a generating facility is entirely dependent on its ability to dispatch at its rated capacity when required to do so to serve load and maintain resource adequacy. When thermal facilities have correlated risk of forced outrages due to extreme temperatures—exacerbated by aging infrastructure, the inability to procure gas during extreme weather events, a lack of firm transmission rights on gas pipelines, and the potential weather-related vulnerabilities of gas supply and pipeline systems—unit outage risks increase significantly, as seen across the country's power system during recent winter storms. These risks need to be accounted for (as PJM and other RTOs do) in estimating the net dependable capacities from facilities and conducting robust planning analysis to address future resource adequacy risks.

Not being in an RTO does not excuse the Companies from properly addressing future resource adequacy risks with prudent, comprehensive planning analyses. The Companies have demonstrated that they have performed no such analysis to appropriately evaluate thermal facilities capacity contributions and appear to misunderstand the concept of capacity accreditation (or capacity contribution) within the context of resource adequacy analysis and solutions to mitigating those risks through robust and sound planning techniques. These weather-correlated risks apply to the Companies coal facilities as well due to systematic risks that cannot be entirely hedged simply by the regular maintenance of their aging generating units. PJM's 2025/26 Base Residual Auction applied 16 percent reduction in capacity contribution to PJM's coal facilities. It is common practice for utilities as well as RTOs to estimate resource accreditation values for the capacity contributions of not only renewables (which the Companies have done, albeit conservatively and applied them incorrectly in the IRP analyses), but also of thermal resources, which the Companies have missed entirely, thereby overstating their expected resource contributions.

Furthermore, the Companies' failure to incorporate rising equipment costs and supply chain constraints for gas-fired generators further skews their modeling in favor of NGCCs. Original Equipment Manufacturers are facing supply constraints to meet unprecedented demand, leading to longer lead times and increased capital costs for turbine procurement, factors that the Companies do not fully account for in their resource expansion modeling, thereby understate expected costs of new NGCCs and SCCTs in their analysis.

Recent Brattle analysis for PJM found that the cost of new entry for greenfield NGCC facilities has increased by 46% since 2022 under conservative scenarios, driven by tight supply for major equipment, labor, and EPC, delayed construction timelines, interconnection difficulties, and inflated firm gas costs.[35]

By continuing to prioritize NGCCs without adjusting for seasonal outages, cost escalations, and supply chain risks, the Companies present an incomplete and overly favorable view of natural gas while dismissing viable alternatives in renewables and storage. A more balanced, technology-neutral approach would provide a clearer and more cost-effective pathway to system reliability. Additionally, the Companies cost assumptions related to small modular nuclear ("SMR") generating facilities are not robust. While the Companies' analysis does not project that SMRs will be cost-effective to develop to meet projected demand, it is still important to develop robust risk-adjusted cost estimates with nascent technologies such as SMRs, which carries both cost risk and technology risk until the technology is full proven and scalable for commercial deployment.

6. The Companies fail to consider market purchases for low-cost energy throughout the entire study window.

While the focus of the IRP is on resource adequacy, the Companies do not incorporate future low-cost market purchases for energy as a viable option throughout the entire study window in their least cost planning analysis. While the IRP primarily focuses on resource adequacy, a cost-effective resource plan would take advantage of low-cost market energy purchases (and look to additional capacity purchases) to reduce the total investment cost over the planning horizon, thereby reducing customer costs further. Companies fail to recognize that strategic market purchases could provide lower-cost alternatives to internal generation, particularly during periods of high renewable generation or regional surplus capacity. Instead, the Companies assume they will purchase no energy from external areas via market transactions—other than their ownership stake in the Ohio Valley Electric Corporation—over the entire planning horizon. This is not only a highly conservative assumption, but also a non-cost optimal assumption that increases customer costs. Given the evolving needs of the system and the fast-changing resource mix across the neighboring systems,[36] leveraging the value of low-cost energy and/or additional capacity purchases is necessary to reduce total investments and customer costs. In the Companies' analysis, it appears that only the current load-correlated level of ATC is assumed for capacity purchase provisions through 2039 in the resource adequacy analysis,

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[35] See Slide 7, PJM QR CONE and VRR Curve Deck, PJM Market Implementation Committee Special Session – Quadrennial Review (2/21/2025). https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250221-special/pjm-qr-cone-and-vrr-curve-deck.pdf.

[36] IRP Volume I, Resource Assessment and Acquisition Plan, pp. 8-20 [PDF 105 of 135].

while in the Companies' production cost analysis no market energy purchases are considered throughout the study horizon.[37]

The omission of market purchases prevents the IRP from fully capturing the economic benefits of market purchases, as it does not account for potential cost savings from purchasing lower-cost energy when available, thereby increasing total investment costs borne by customers. Many utilities regularly incorporate market transactions into their modeling, recognizing that importing power at times of need can be more cost-effective than building new generation. Despite the Kentucky Public Service Commission's ("Commission") statement in the recent CPCN proceeding that "[w]ith surrounding regions concerned about being energy inadequate, the Commission would rather the Commonwealth standout as a state with enough power to meet customers' needs,"[38] not considering market purchases from regional neighbors does not support the mission to produce the lowest cost energy to customers. The Companies recognized the savings value of regional transactions when they joined the Southeast Energy Exchange Market ("SEEM"). The SEEM, which the Companies participate in, facilitates bilateral energy transactions, yet the IRP fails to analyze the role of SEEM transactions in meeting future energy demand.

Failure to fully include the benefit of market sales and purchases is also highlighted in the December 2024 SEEM Monthly Audit Report.[39] By ignoring low-cost market purchases, the Companies may be overcommitting to internal generation, leading to higher customer costs and an underutilization of existing market structures that facilitate valuable trade benefits and potential reliability benefits (through geographic diversity in net load among the Balancing Areas). A more balanced IRP would model market participation alongside internal resource additions, ensuring that the full range of cost-effective options is considered before committing to capital-intensive new generation projects.

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37 See PSC DR1-16.

38 *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order at 177-78 (Ky. PSC Nov. 6, 2023).

39 See Monthly Audit Report on the Southeast Energy Exchange Market for December 2024, prepared by Potomac Economics (January 31, 2025).

IV. Recommendations for an Improved IRP Analysis and Resource Plan

Based upon our review of the Companies' IRP and related interrogatory responses, we provide the following recommendations.

- **Recommendation #1:** Consider realistic data center load growth and potential load flexibility of data centers locating in the Companies' territories.

We recommend that the load forecast analysis carefully consider the data center load growth in the Companies' territories, as this assumption largely drives the need for new generation investments based on the Companies' IRP. While it is essential to anticipate a realistic level of the overall magnitude of load growth, it is equally important to assess the potential flexibility of new data center loads and the preference of data center customers to be served by carbon-free resources. The Companies currently estimate that data centers will operate with load factors near 95%, yet emerging research and industry practices indicate that data centers—particularly those specializing in AI—may provide significant operational flexibility. AI-specialized data centers have *temporal flexibility*, allowing non-urgent computational workloads such as model training to be scheduled during off-peak hours. Additionally, *spatial flexibility* enables data centers to shift workloads across different geographic locations, optimizing electricity usage based on grid conditions and energy costs. [40]

Given these capabilities, data centers locating in Kentucky may be well-positioned to participate in demand response programs, reducing their power consumption during peak periods without compromising essential operations. Existing initiatives, such as ERCOT's *Controllable Load Resources* program and Google's *carbon-aware computing strategy*, demonstrate that large-scale data centers can successfully adjust their power usage in response to grid needs. Therefore, in modeling future peak load and new generation needs, the Companies' analysis should incorporate realistic assumptions about data center load flexibility and actively explore demand response opportunities. If the duration of resource adequacy risks is longer than the potential duration of flexible demand response, new investments may be necessary to maintain reliability. However, those new resources could very well be cost-effective solar and storage facilities, which are preferred by data center customers. The analysis needs to better reflect

[40] See Norris, Tyler H., et al., "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute for Energy, Environment & Sustainability, 2025, 10-12, accessed February 26, 2025. https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf.

realistic resource contributions of renewables, and not artificially escalate their costs as discussed in additional recommendations below. Considering demand flexibility approaches carefully help mitigate the need for costly new generation capacity, improve grid reliability, and support more efficient use of existing infrastructure.

- **Recommendation #2:** Update the IRP analysis to ensure that it reflects realistic resource contributions for renewable generation and thermal facilities.

The Companies' analysis should be updated to model additional sensitivity cases that include (1) non-zero solar capacity contributions in the winter, (2) non-zero wind capacity contributions in both summer and winter, (3) a derating factor to the capacity contributions of "fully dispatchable" thermal resources under weather-normalized analysis, and (4) higher forced outage rates on thermal facilities during extreme winter weather events to reflect realistic temperature-correlated outage risk.

a) We recommend that the analysis reflect the following industry data and practices for non-zero solar capacity contributions in the winter and non-zero wind capacity contributions in both the summer and winter:

i) PJM uses a sophisticated ELCC model to estimate the capacity value of resource types. For the 2026/27 season, the resource adequacy contribution of solar is 8% and onshore wind is 34%.[41]

ii) MISO is beginning a transition to a resource accreditation methodology that is more sophisticated than what it used historically. In past capacity auction cycles, MISO has valued the capacity contribution of wind and solar at 53% and 5%, respectively, of nameplate capacity during the winter, and at 18% and approximately 50%, respectively, during the rest of the year.[42]

iii) TVA recognizes a 10-15% net dependable capacity (NDC) for solar in winter when penetration levels are below 1,000 MW.[43]

iv) Georgia Power Company recognizes a 35% ELCC for onshore wind power.[44]

[41] https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf.

[42] For the 2024/25 capacity auctions, wind in MISO is accredited at 18.1% of nameplate capacity for the summer, 15.6% for the fall, 53.1% for the winter, and 18.0% in the spring. *See* https://cdn.misoenergy.org/Wind%20and%20Solar%20Capacity%20Credit%20Report%20PY%202024-2025632351.pdf

[43] See pg. 4-4 of TVA 2025 Draft IRP.

[44] See Georgia Power Company 2025 IRP, Technical Appendix Volume 2 Public Disclosure, Resource Mix Study at p. 26, Table 5, January 2025.

b) *Apply a derating factor—based on actual and class-average unit eFORd—to capacity contribution of "fully dispatchable" thermal resources in weather-normalized capacity expansion simulations to Coal, NGCC, and SCCTs. For winter peak analysis, employ higher outage rate assumptions based on temperature-correlated outage data from several historical weather years and based on recent experience during extreme winter weather events in and around Kentucky and PJM region. We recommend that the Companies' analysis*:
   i) Incorporate data reflecting the performance of natural gas and coal facilities during Winter Storm Elliott and adopt PJM's estimation of outage risks and capacity contribution reductions, including for gas facilities that have dual-fuel capability with on-site fuel back-up, and for those with firm gas service. For both gas and coal facilities, the analysis should evaluate whether the supply and storage systems are appropriately weatherized.
   ii) Model risk-adjusted scenarios based on these learnings, especially as they relate to the reliability risks of and risk drivers for natural gas and coal facilities. The extent of the outages during Elliot was vast. In PJM, over 11 GW of gas facilities and about 8 GW of coal facilities tripped largely due to cold weather freezing and fuel supply issues.[45]

- Modify the overnight capital costs for wind resources such that assumed costs more accurately reflect recent, relevant wind project costs rather than using the same benchmarking ratio (49%) as used for solar. Run an RFI/RFP for market price discovery and potential resource procurement.
  - The Companies' existing methodology estimates that a wind project in Indiana would cost $2,355/kW in 2024; however, installed costs for projects installed in MISO between 2022 and 2023 have a capacity-weighted mean of approximately $1,750/kW (in 2023$). Projects in SPP, ERCOT, and PJM have lower averages.[46]
- Model seasonal forced outages of thermal facilities during winter peak and extreme winter weather events based on temperature-correlated outage risks from historical weather years.

[45] See Figure 31, on p.51 of PJM's Winter Storm Elliott Event Analysis and Recommendation Report, dated July 17, 2023. https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx

[46] Lawrence Berkeley National Laboratory, Land-Based Wind Market Report, 2024 Edition, pp. 43 [PDF 59 of 92]. https://emp.lbl.gov/wind-technologies-market-report.

- **Recommendation #3:** Issue competitive solicitation requests for proposals of renewable energy and energy storage systems to test market assumptions and implement IRP plans.

We recommend that the Companies' analysis subsequently support the issuance of RFPs that are appropriately tailored to meet the Companies' projected capacity needs following the conclusion of the 2024 IRP proceeding and prior to moving forward with the development of any particular generation resource (or contract execution). Issuing RFPs before acquiring new generation resources is consistent with best resource planning practices.[47] At the conclusion of an IRP process, it has become industry standard to issue an RFP for renewable energy resources.[48] Obtaining real market data directly from project developers (including SREA members) via RFPs is the most accurate way to develop present day cost expectations for most resources, particularly since the costs to procure new resources change constantly.[49] RFPs allow utilities to test the market against IRP assumptions and use competition to act in ratepayers' best interests. RFPs should be flexible, enabling renewable energy developers to bid in many different project sizes, locations, technologies, and contractual types.[50] Issuing RFPs is a zero-risk action item that should be included with every IRP, including this one. The Companies' IRP states that "[a]s needed, the Companies use an RFP process to obtain offers for energy and capacity from the electricity market."[51] We recommend a transparent process for RFP issuance and evaluation and the capacities that will be sought via such RFPs so that there is efficient price discovery and market response to the projected needs.

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[47] *See* Synapse Energy Economics*, Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future,* November 2024 (Revised December 6, 2024) at 31, available at https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf ("The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals."); *see also* John Wilson, Mike O'Boyle, Ron Lehr, Mark Detsky, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (April 2020) at 1, available at https://energyinnovation.org/wp-content/uploads/2020/04/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices.pdf.

[48] *See e.g.,* Georgia Power Company 2025 IRP at 60 (explaining the utility's plan to "[i]ssue RFPs designed to procure energy from up to 4,000 MW of renewable resources by 2035, including the 2026 Utility Scale RFP targeting 1,000 MW of utility-scale renewable resources expected to reach commercial operation between November 30, 2030, and November 30, 2032.").

[49] *See* Synapse Energy Economics*, supra* note 47 at p. 31.

[50] *See* Wilson et. al., *supra* note 47 at 31 (Model Process and For Bid Evaluation).

[51] LG&E/KU IRP at pp. 8-13.

- **Recommendation #4**: Enable greater opportunities for customers to produce zero-emissions generation beyond the Green Tariff Option #3.
  - The Green Tariff Option #3 allows for customers to purchase energy from a renewable energy generator through a Renewable Power Agreement with the Companies. The Companies enter into a PPA with a renewable developer and into the Renewable Power Agreement with interested customers to supply the energy necessary.[52] This tariff option, though, is capped at 100 MW per customer. Additionally, the Companies claim recent issues with their solar PPAs, in which three of six have been cancelled and the Companies do not have certainty that the remaining three will be constructed.[53]
  - In 2019, the Companies entered into an agreement with Dow and Toyota to procure 200 MW of renewable energy. After issuing a RFP, the Companies signed a PPA with Rhudes Creek Solar, LLC; however, the Rhudes Creek Solar developer has been unable to secure local approvals and will likely be unable to construct the facility for the negotiated price.[54] As evidenced, the Green Tariff Option #3 places a low limit on the amount of renewables that can be attributed to a customer (100 MW) and does not provide certainty that these resources will be constructed based on recent experience. The Companies state that the solar in the Enhanced Solar Resource Plan could be added by the Companies in a scenario where solar prices fall faster than the NREL projections; however, they do not give a cost estimate at which that would happen nor does the Enhanced Solar Resource Plan have an effect on the natural gas-fired and battery storage resources planned to be built in the Recommended Resource Plan, potentially resulting in unnecessary overbuilding of resources.
  - We recommend that the Green Tariff option #3 be further expanded and that an annual procurement process is created in order to maintain up-to-date information on costs and adopt flexibility in contracting terms to maximize RFP bids. We also recommend routine bid refreshes when bid costs have structurally changed between issuance of RFP and consummation of transactions.
- **Recommendation #5**: Consider realistic cost savings and resiliency benefits that could be provided by capacity imports from neighboring regions and proactively plan transmission enhancements to increase ATC to leverage greater imports from neighboring regions. See Recommendation 6 below.

[52] See LG&E and KU Renewable Power Agreement.

[53] IRP Volume III, Resource Assessment, Section 3.2 ("Capacity and Energy Need with Existing and CPCN-Approved Resources), Footnote 31, pp. 20 [PDF 94 of 259].

[54] See PSC DR1-3.

- **Recommendation #6**: Consider the full scope of economic benefits of assets, including realistic energy value, beyond just the resource adequacy value**.**
- **Recommendation #7**: Integrate improved, proactive local and regional transmission planning.

While the Companies discuss their local, regional, and interregional planning processes in their IRP, their analysis should consider ways to integrate proactive transmission planning that employs a multi-driver needs assessment and uses a multi-value framework to assess potential projects. The Companies claim that "[a] broad-brush view exists that an expanded grid capacity, especially regional and interregional, is needed to accommodate generation retirements, new power supply, and to improve resiliency and reliability."[55] While the Companies view is that their current planning process is sufficient to meet the reliability needs of the system, by not proactively planning for a variety of future scenarios, they are failing to take advantage of significant cost savings and resiliency benefits for Kentucky ratepayers. Therefore, we recommend that the Companies' planning processes consider ways to integrate improved transmission planning into their local and regional processes, allowing them to further leverage imports via interregional projects that enhance ATC, as discussed in Recommendation 4 above.

The Companies' analysis should consider the recently updated local transmission planning process implemented by Duke Energy (Duke Energy Carolinas and Duke Energy Progress). The Carolina Transmission Planning Collaborative released its first Multi-Value Strategic Transmission ("MVST") Study in 2024 to consider possible transmission solutions to issues based on several future scenarios.[56] The MVST planning process incorporates a multi-value cost-benefit framework that considers: (1) avoided capacity costs; (2) capacity savings from reduced losses; (3) congestion and fuel savings; (4) energy savings from reduced losses; (5) avoided customer outages; (6) avoided transmission investment. By studying a holistic view of the system, based on several possible future scenarios, this process is able to identify potential longer-term upgrades that provide greater overall benefit to the system and reduces costs to ratepayers.

Beyond local transmission planning, additional benefits to the system and cost savings for ratepayers can be unlocked with improved regional transmission planning. Transmission planning processes should be aligned with the other SERTP Sponsors to implement proactive regional transmission planning across the Southeast. This effort should focus on identifying

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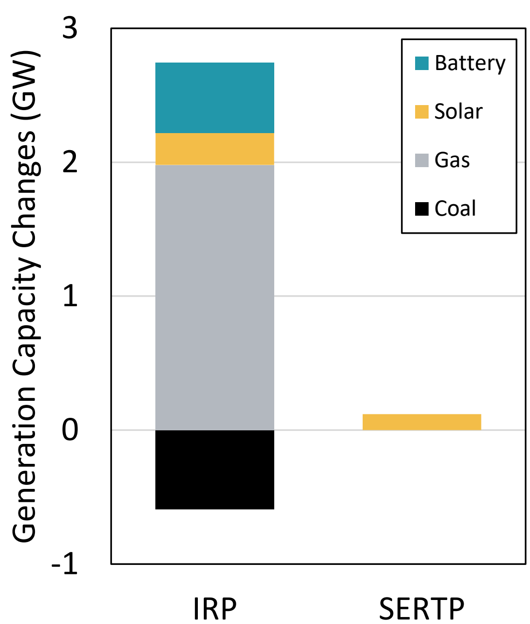
[55] IRP Volume III, Transmission Section, pp. 19 [PDF 211 of 259].

[56] See 2024 Multi-Value Strategic Transmission (MVST) Study, Carolinas Transmission Planning Collaborative.

cost-effective regional upgrades that lower the costs and risks of accessing low-cost generation resources, leverage load diversity and reserve sharing to reduce resource adequacy costs, expand capacity for efficient market transactions between utilities, and avoid less efficient, lower capacity local upgrades. Additionally, increased regional (and interregional) transmission will provide increased resiliency to extreme weather events. Working with other Sponsors to develop multiple future regional scenarios that plan for a range of load growth and generation resource outlooks can enable the identification of congestion and quantification of production cost savings.

The current SERTP process hitherto has not identified a more efficient or cost-effective regional transmission project because of its narrow scope of only considering the cost savings from avoided local reliability projects. If the process instead considered production cost savings, load diversity savings, added savings from resiliency, and avoided transmission costs and losses, the process may be able to identify cost-effective backbone upgrades needed to support system changes and lower costs to ratepayers. Additionally, the Companies claim that they "ensure transmission planning is aligned with the real, forecasted needs and use of the Transmission System."[57] Yet, there is a large discrepancy in the 2024 SERTP Regional Transmission Plan and the Companies' 2024 IRP resource changes, as shown in Figure 5.

FIGURE 5. LG&E/KU IRP VERSUS SERTP REGIONAL PLAN RESOURCE CHANGES THROUGH 2034



[57] IRP Volume III, Transmission Section, pp. 19 [PDF 212 of 259].

Figure 5 shows the resource changes through the end of 2034 included in the Recommended Resource Plan versus those included in the SERTP regional modeling. It appears that the two processes are not coordinated and thus are simply not effective in the desired mandate of holistic, cost-effective integrated planning.[58]

[58] For more information on the SERTP planning process and recommendations for an enhanced SERTP process, please see the "Southeast Regional Transmission Needs and Planning Improvements" presentation presented by consultants at The Brattle Group at the SERTP Order 1920 Stakeholder Engagement meeting in January 2025 at Exhibit 1. We understand that the full report on Southeast Regional Transmission Needs and Planning Improvements is expected to be released publicly on March 24, 2025.

EXHIBIT 1

Southeast Regional Transmission Needs and Planning Improvements

SERTP ORDER 1920 STAKEHOLDER ENGAGEMENT MEETING

PREPARED BY

J. Michael Hagerty

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PREPARED FOR

CCEBA Carolinas Clean Energy Business Association

srea SouthernRenewable.org

CEBA Clean Energy Buyers Association

JANUARY 29, 2025

UPDATED: MARCH 5, 2025

Report funded by the Clean Grid Initiative, a project of Multiplier

Brattle

Southeast Needs to Invest in its Transmission Infrastructure

Facing accelerated load growth and increasing reliability risks, Southeast utilities need to invest in their transmission systems to **improve reliability** and **reduce cost**

Local Reliability Needs Increased Transmission Investment by 4x

- Local reliability projects are increasing due to load growth, new generation, and aging infrastructure
- No investment in regionally-planned transmission projects

Load Growth Increases Need for Regional Transmission Investment

- Growth being driven by commercial and industrial activity will increase needs for infrastructure
- Proactive transmission upgrades can increase system capacity and allow new loads to interconnect more quickly

Insufficient Regional Capacity Increases Winter Risks and Customer Costs

- Regional transmission capacity increases resilience to extreme weather events and reduces likelihood of outages
- Regional projects can reduce total annual system costs, including production costs, capacity costs, local transmission costs, etc.

Proactive Planning De-Risks Generation Needed to Serve Load

- New load requires additional generation resources to enter the system that are currently limited by lack of capacity
- Proactive regional planning can build out upgrades prior to need and reduce new resource development timelines to efficiently meet IRP needs

Current Southeast transmission planning process is **reactive** and **narrow in scope**, leading to (1) inefficient transmission investment, (2) longer timeframes for resource additions, and (3) lower reliability at higher cost

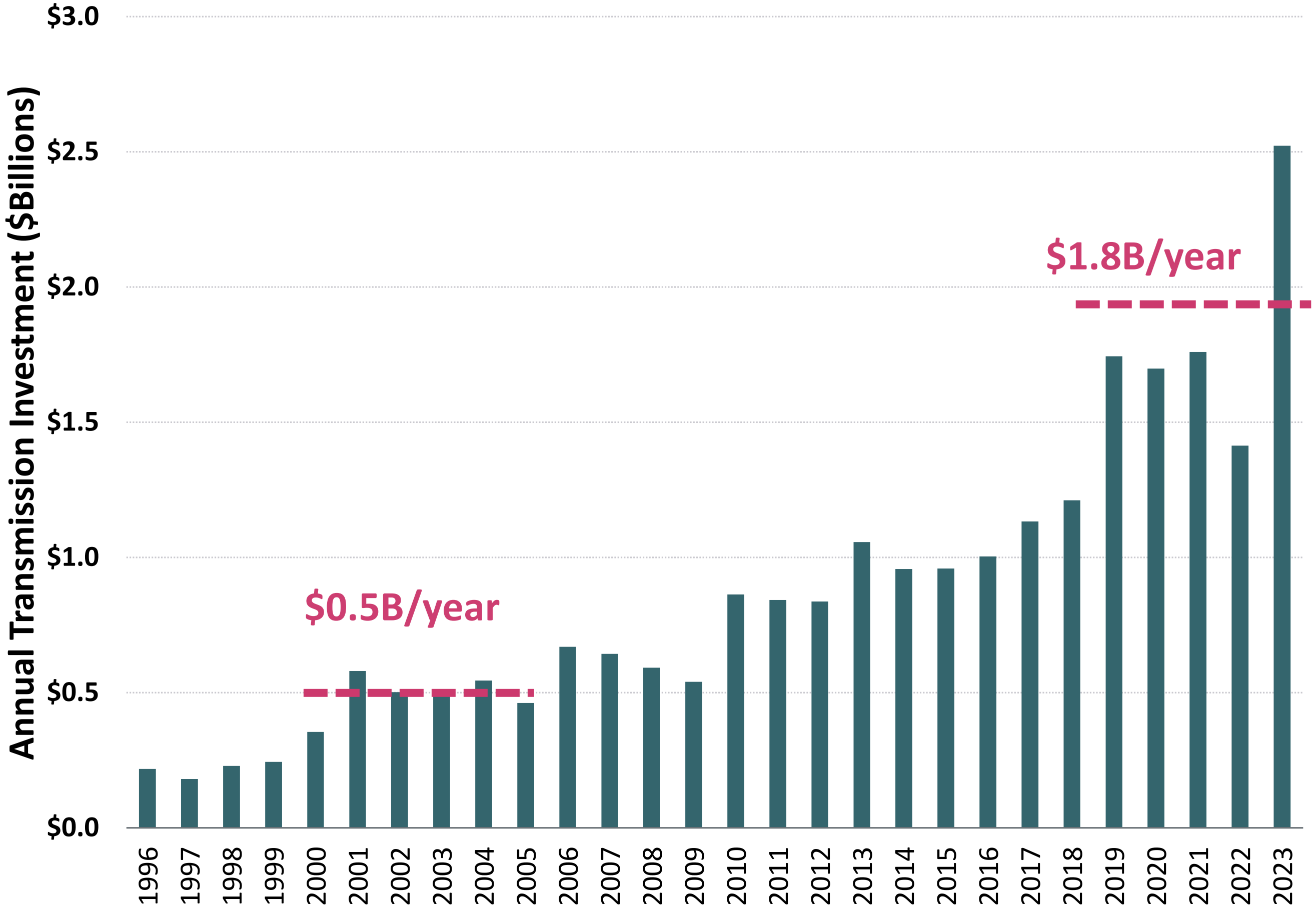
4x Increase in Reliability-Driven Local Transmission Needs

Transmission investment of major investor-owned utilities in the Southeast increased from **$0.5 billion per year in the early 2000s to $1.8 billion per year in the past 5 years**

Increased transmission costs in the Southeast (and across the country) are driven by **local reliability projects** to support load growth, replace aging infrastructure, and generator interconnection

Building local projects can overlook opportunities for more cost-effective transmission upgrades by addressing transmission needs through less-efficient locally-planned projects

Annual Transmission Investment in SERTP Region
(Southern Company, Duke, LG&E/KU)



Sources: The Brattle Group analysis of FERC Form 1 Data

Transmission Needed to Cost Effectively Serve Growing Load

Southeast utilities are projecting 15-35% higher load by 2035 due to new data centers and manufacturing facilities that will drive further transmission system needs

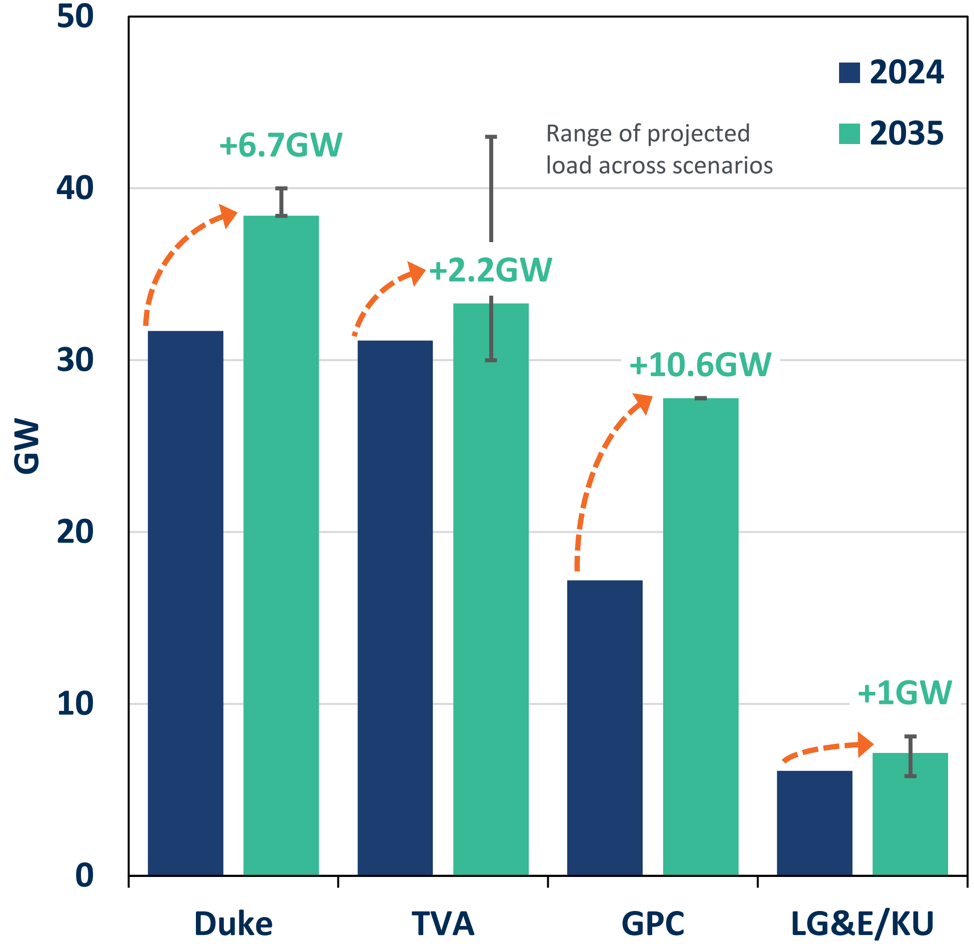
- Duke (DEC/DEP): +7 GW to +9 GW
- TVA: +1 GW to +12 GW across scenarios (base: +2 GW)
- Georgia Power (GPC): +8 GW

Combining local planning with improved regional planning will support utilities in meeting the significant increase in load and generation at lower total costs and allow for efficient interconnection of new loads

Effective regional transmission planning can support utilities in meeting multiple needs at an overall lower cost

- Regional transmission planning is comparable to multi-utility capacity sharing agreements in which Southeast utilities have collaborated to collectively manage costs and share the benefits

Projected Peak Load Growth by 2035



Regional Transmission Reduces Risks of Extreme Weather

In addition to load growth, recent extreme heat and cold weather events have stressed the Southeast grid and lead to reliability events that could have been avoided with increased regional capacity

Winter Storm Elliott in December 2022 demonstrated the need for access to additional import capacity to maintain grid reliability in the Southeast as several utilities were forced to order firm load shedding:

- DEC and DEP: Approximately 5,000 MWh over four hours
- TVA: Approximately 19,000 MWh over seven hours
- LG&E/KU: Approximately 1,200 MWh over four hours

Despite similar generation outages, Georgia Power was able to avoid firm load shedding through imports from Florida; similarly, PJM avoided outages across its system by relying on its regional capacity and interregional capacity with MISO to maintain system reliability

Regional and interregional transmission acts as an insurance policy against future extreme conditions by providing access to a wider set of generation resources to serve load that can increase reliability and reduce cost risks for customers

Source: FERC, NERC and Regional Entity Staff Report, “Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott,” October 2023.

Transmission Upgrades De-Risk New Generation Additions

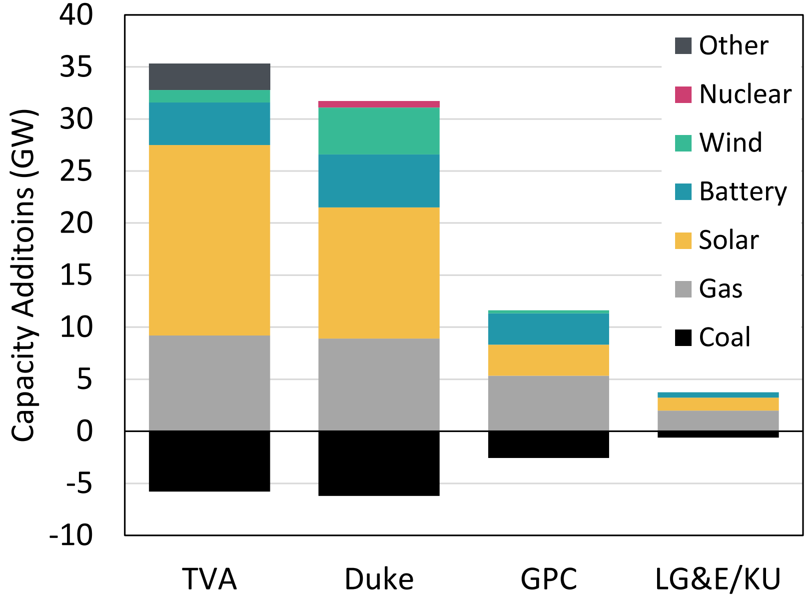
Southeast utilities will need to **interconnect more than 80 GW of new capacity** by 2035 (~10 GW/year) based on recent IRPs

- New generation requires identification and construction of network upgrades prior to interconnection
- Generation resource types are changing due to coal retirements and the addition of new gas, solar, and storage
- New generation resource types and locations will shift flows across the grid and increase regional transmission needs

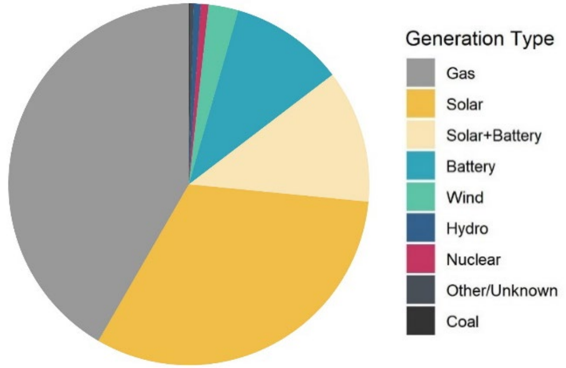
SERTP does not currently study transmission to support the future generation identified in Sponsors' IRPs; instead, higher cost upgrades will be identified based on interconnection studies

Lack of capacity to interconnect resources already identified as needed will slow the pace of generation additions and result in either (1) relying on higher cost resources to serve load or (2) delaying addition of new loads

New Generation Needs in Recent IRPs



Resource Types in Generator Interconnection Queues Across SERTP

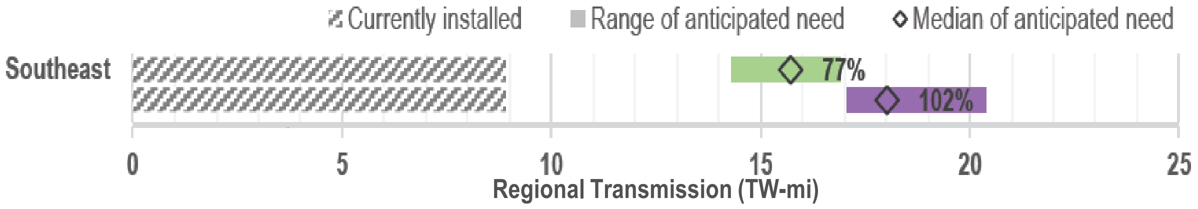


Total: 110 GW

Southeast Transmission Needs Highlighted in Recent Studies

National Transmission Needs Study (2023)

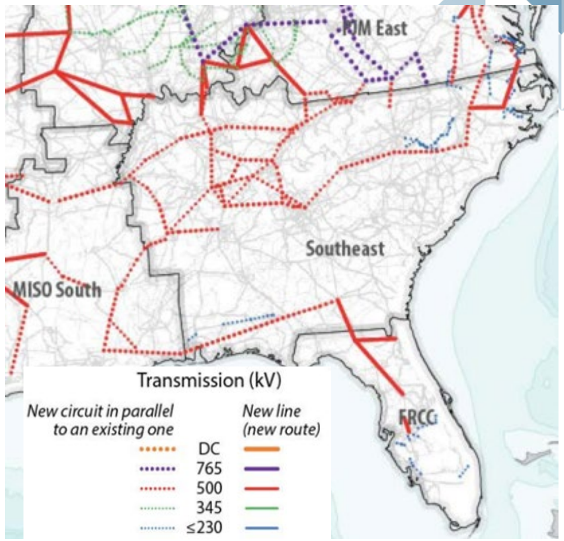
Summarizes 300 future scenarios and sensitivities from 6 independent studies for 2030, 2035, and 2040. By 2035, Southeast will need **7 TW-miles of new within-region transmission** and significant expansion of interregional transmission, ranging from **5.1 – 39.9 TW-miles with neighboring regions**.



Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.

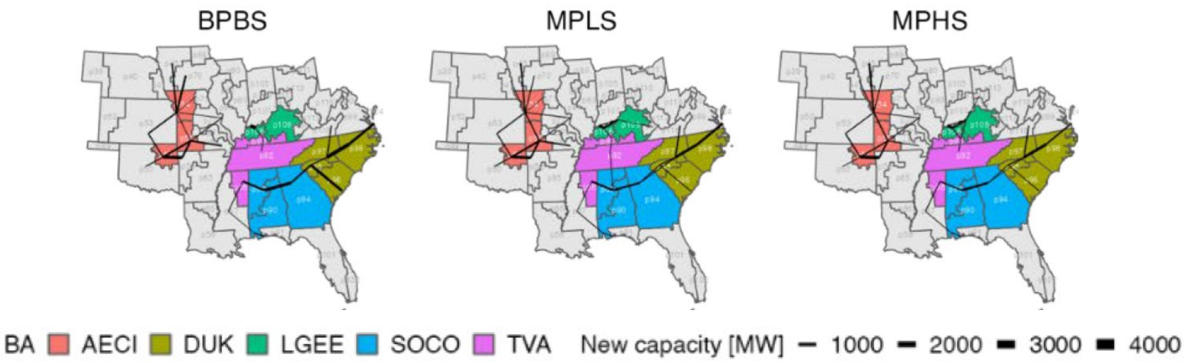
National Transmission Planning Study (2024)

Conducted zonal capacity expansion & RA modeling through 2050 under 96 scenarios. Mid-demand, 90% emissions reduction AC scenario strengthens existing 500 kV networks and connects SERTP to the Midwest and Plains through 345 kV and 500 kV lines. **Enables flows across north-south and west-east interfaces to key load centers**.



NREL/LBNL Solar and Storage Integration Study (2024)

Investigates how higher levels of solar and storage impact costs, reliability, and operations in 2035 and the benefits of increased operational coordination among utilities. In lower-solar scenarios, **most additions were regional.**



NREL/LBNL Solar and Storage Integration Study (2024)

Transfer capability analysis between pairs of neighboring transmission planning regions and recommended "prudent" interregional transmission additions to maintain reliability. Transmission expansion into the SERC-E region (DEC/DEP and SCRTP) **is justifiable based on reliability alone**: 2.5 GW by 2033 from the Southeast region and 1.6 GW from PJM to alleviate resource deficiencies in the region.

Table ES.1: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)

Regional Transmission Planning vs. Local Planning and IRPs

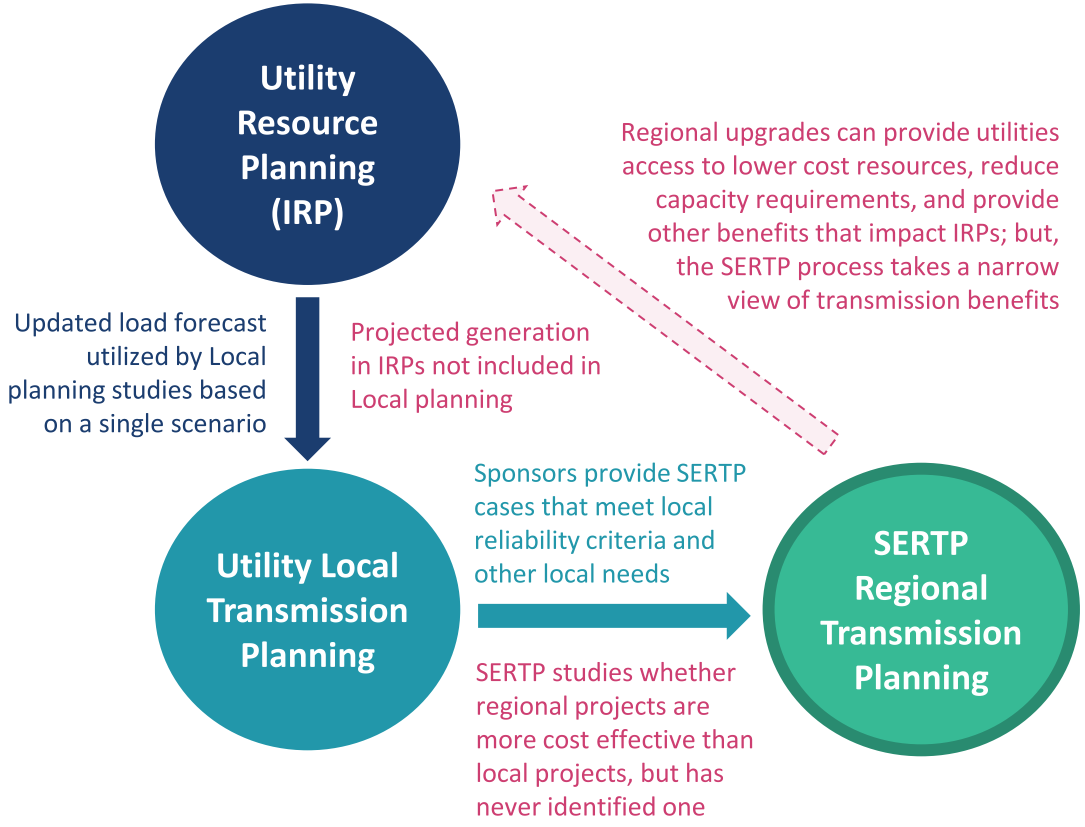
SERTP's regional planning models reflect system conditions studied in each Sponsors' local transmission planning study

- Each Sponsor completes local transmission planning that incorporates the latest load forecast and a limited set of generation additions (i.e., resources with IAs) and retirements
- Sponsors identify local upgrades needed to resolve reliability violations based on NERC criteria
- Duke studies future scenarios and multi-value upgrades via the CTPC MVST local planning process, but the cases it provides to SERTP are based on its local reliability study

SERTP planning does not account for the full set of resources identified in recent IRPs, limiting SERTP from identifying least-cost upgrades to support new generation additions

Regional planning can identify upgrades that provide utilities access to a broader set of resources in their IRPs and for dispatching generation more efficiently

Coordination across Resource Planning and Transmission Planning



SERTP Assumptions are not Aligned with Local Resource Planning

SERTP models system conditions based on Sponsor-provided assumptions:

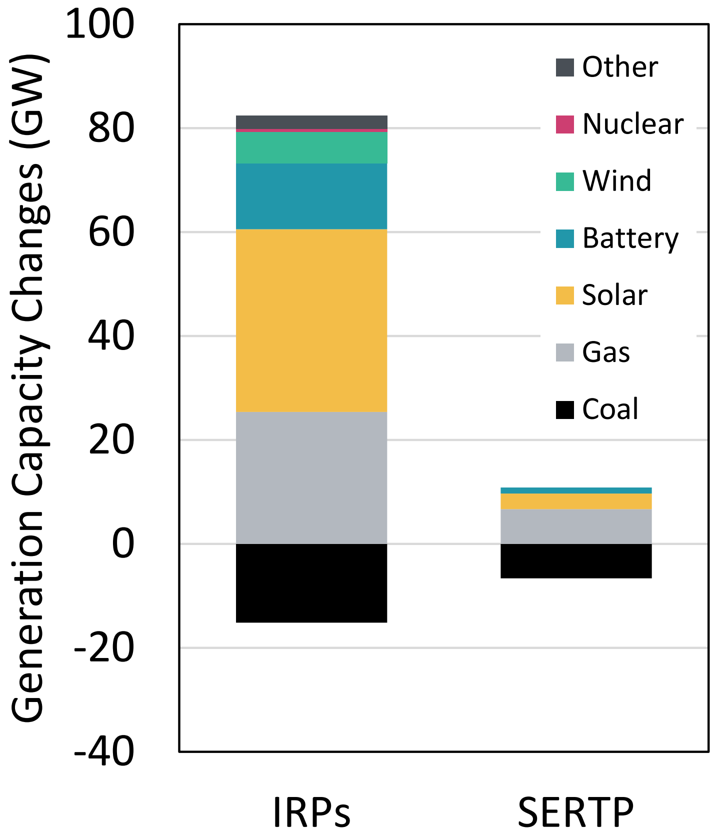
- Load forecasts, which are aggregated into cumulative non-coincident peak summer and winter forecast
- Some changes in generation capacity (including EE and DR)
- Transmission commitments that source/sink across two NERC BAAs

Significant discrepancies between projected generation resources in SERTP Sponsor IRPs and SERTP planning models

- SERTP regional model only includes 8% of solar additions, 27% of gas additions, and 41% of coal retirements identified in the latest TVA, Duke, GPC, and LGE/KU IRPs by 2035
- In some cases, utilities are not including resources that they already requested approval from its state commissions for construction
- SERTP includes hypothetical "proxy units" to ensure there are sufficient resources to meet load, instead of utilizing available IRP portfolios

SERTP's single future scenario does not assess how the regional system could adapt to uncertainties in future changes (e.g., high growth scenarios or rapidly evolving generation resource mixes)

IRP vs SERTP 2035 Generation Changes
(TVA, Duke, LG&E/KU, GPC)



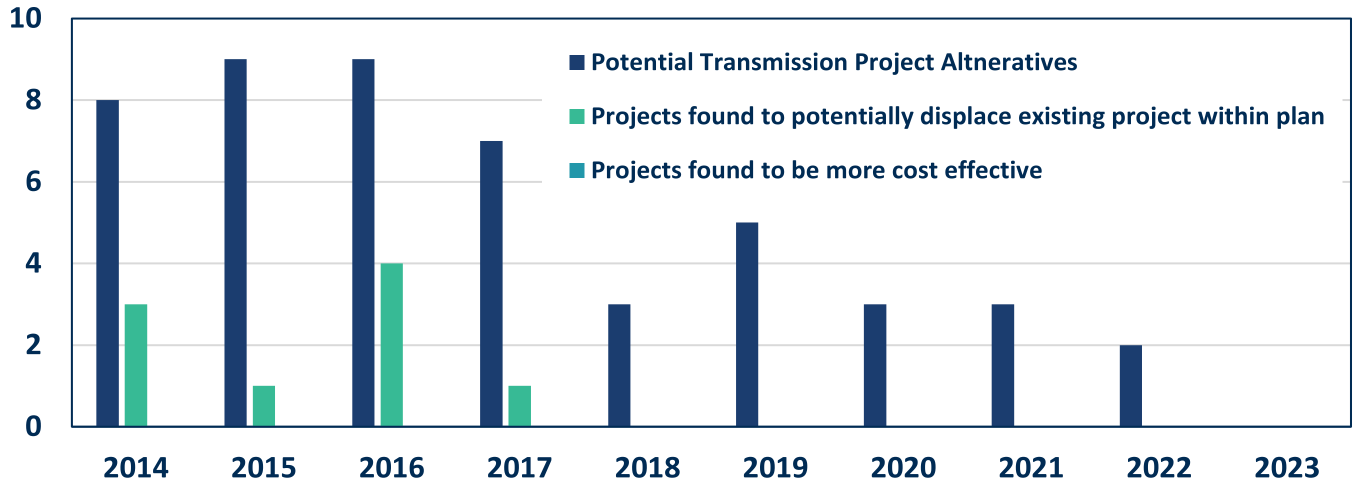
SERTP Has Not Identified Cost-Effective Regional Projects

Based on the Sponsor-provided plans, SERTP conducts a reliability study to determine if regional projects could provide a more cost-effective solution than proposed local upgrades based on the following criteria:

- Ability to resolve reliability violations based on NERC criteria
- Project feasibility, i.e. viability of constructing and tying in the proposed project by the in-service date
- Avoided local transmission costs
- Ability to reduce real power losses

SERTP **has never identified a more efficient or cost-effective regional project** to include in its annual regional plan despite studying 49 alternative projects due to the limited scope of benefits analyzed

Potential Transmission Project Alternatives Evaluated by SERTP



Total: 49

Potential displacement: 9

More cost effective: **0**

Key Shortcomings in the SERTP Regional Planning Process

Local Transmission Plans

- Sponsors' local transmission plans are developed with little transparency and do not account for multiple drivers of transmission needs
- Local transmission planning studies are not closely integrated with future planned generation additions based on Sponsors' IRPs, limiting scope of system needs identified in SERTP studies

Preliminary Expansion Plan

- Preliminary SERTP expansion plan is an aggregation of local plans to confirm simultaneous feasibility under all applicable reliability standards
- Only one future scenario is modeled based on local plan assumptions, failing to account for the role of regional projects to more efficiently address future outcomes given high levels of uncertainty

Regional Planning Analyses

- Limited scope of scenarios and regional cost savings of transmission quantified in SERTP planning studies
- Economic and policy studies do not provide reasonable opportunity to identify the most beneficial projects
- Study design results in SERTP never identifying a need for any regional projects in its 10-year Plan

Regional Transmission Plan

- SERTP regional transmission plan mimics the local planning results, failing to identify sufficient cost savings and other benefits to identify a regional transmission need and provide low-cost options for accessing a wider range of resources in IRPs and generation dispatch
- Stakeholder engagement does not incorporate meaningful recommendations and does not include active state participation.

SERTP Can Build on Order 1920 to Improve Regional Planning

FERC Order 1920 better aligns regional planning with industry-wide best practices that have been implemented across the country for comprehensively assessing long-term regional transmission needs

Southeast utilities will need to update its regional planning process to meet Order 1920 requirements:

- Complete a comprehensive long-term (20+ year) planning process every 5 years that considers at least 7 drivers of transmission needs plus asset refurbishment and generator interconnection needs
- Develop at least 3 plausible and diverse scenarios, including at least 1 "stress test" sensitivity
- Quantify at least 7 benefits metrics for upgrades that meet long-term regional needs
- Consider a broader set of solutions including grid-enhancing technologies (GETs), upsizing existing lines
- Develop default or state-sponsored cost allocation mechanisms
- Engage regional state entities through the transmission planning process

SERTP is in the process of developing its Order 1920 compliance filing and seeking input from stakeholders; in parallel, SERTP is conducting an engagement period with Relevant State Entities

Framework for Improved SERTP Regional Planning Process

Experience across the industry over the past 10-20 years provides several proven planning practices that can reduce total system costs and risks:

- Proactively and holistically plan for future generation and load by incorporating realistic projections of all needs: the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investments; critical to avoid siloed, incremental planning processes.
- Account for the full range of transmission needs and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits
- Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events
- Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach
- Jointly plan interregional projects across neighboring systems to recognize regional interdependence, increase system resilience, and take full advantage of scale economics and geographic diversification

* Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

Enhanced SERTP Regional Transmission Planning will Reduce Costs and Increase Reliability of the Southeast Grid

SERTP can leverage industry-wide experience over the past 20 years by implementing proven practices to reduce system costs and risks, including the MISO LRTP and CTPC/Duke MVST planning processes

I. Improve Existing Planning Process

1. **Increase transparency** of planning assumptions and study results
2. **Engage state commissions/ agencies** to actively participate in planning process and analysis of regional upgrades that reduce costs and address state policies
3. Expand solutions studied to reflect a **least-cost "loading order"** that maximizes existing grid, upgrades existing lines, and build new lines

II. Expand SERTP Planning Capabilities

4. Develop **multiple scenarios based on recent IRPs** to plan for a range of load and generation portfolios
5. Accurately identify congestion and quantify cost savings of regional upgrades via **regionwide production cost model**
6. Develop guidelines to account for **comprehensive set of cost savings & other benefits** when analyzing regional upgrades

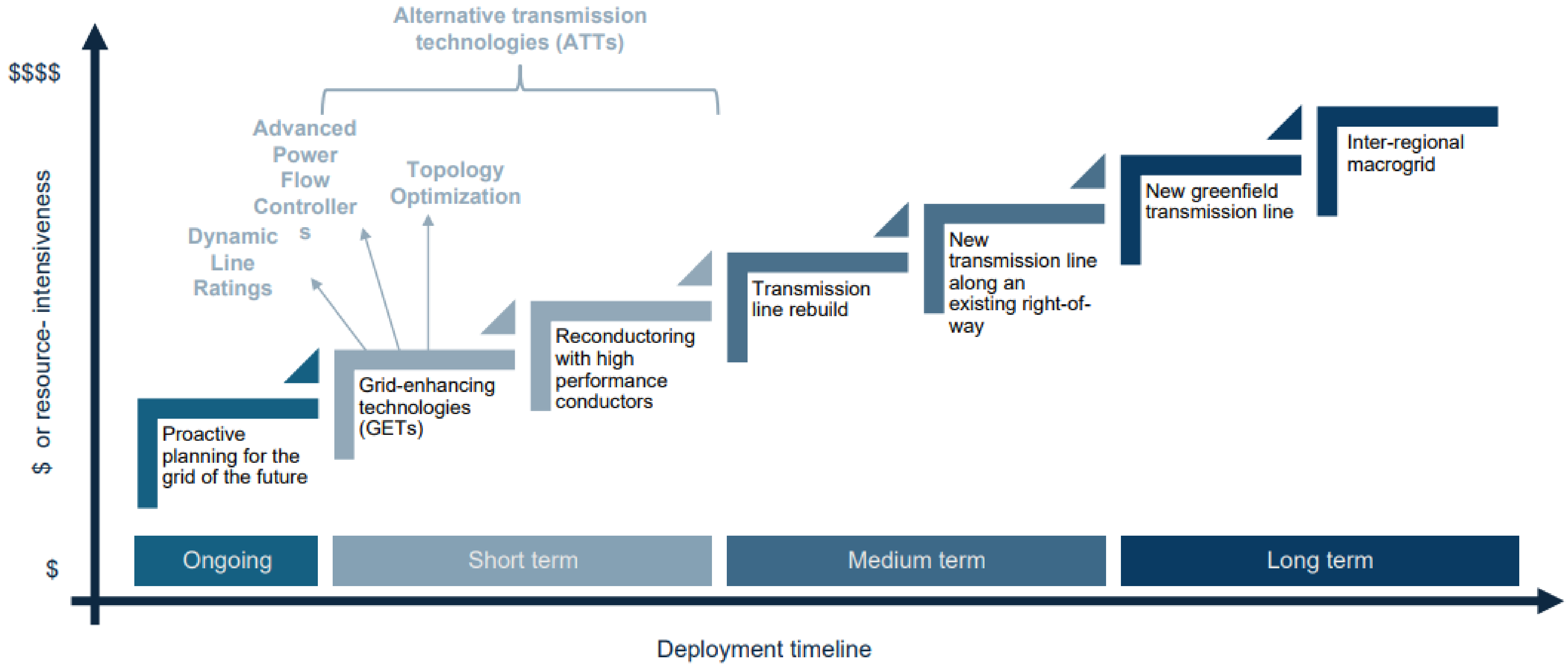
III. Implement Comprehensive & Proactive Planning Process

7. Implement **multi-driver approach to identifying regional & interregional needs** and candidate solutions
8. Estimate cost savings and other benefits of solutions **over the entire useful life of the assets**
9. Establish regional cost allocation that reflects **beneficiaries pays and cost causation principles**

Expand Solutions to Reflect a Least-Cost "Loading Order"

Serving near-term load growth while maintaining an affordable system requires planners to:

- Maximize the capability of the existing grid using GETs and Remedial Action Schemes (RAS)
- Proactively identifying upgrades to the existing system and new builds to add capability



Source: Sarah Toth (RMI), Alternative Transmission Technologies in Order 1920 and PJM, September 6, 2024.

Study Broader Set of Regional Cost Savings of Transmission

SERTP can take advantage of the best practices developed across the industry over the past 20 years for estimating transmission benefits

- Analytical approaches for quantifying transmission benefits have been documented in a report submitted to FERC in the ANOPR process and highlighted in Order 1920
- Regional planners have implemented these analyses in studies to justify major investments in regional transmission

Additional approaches continue to be developed to account for the benefits of transmission:

- Use weather-reflective (rather than weather-normalized) production cost and long-term expansion planning simulations (e.g., for 20-30 weather years)
- Production cost simulations with both day-ahead and real-time cycles to capture unpredictable real-time challenges and associated value

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Planners Identified Upgrades based on Expanded Cost Savings

SPP 2016 RCAR, 2013 MTF

Quantified

1. **production cost savings***
   - value of reduced emissions
   - reduced ancillary service costs
2. avoided transmission project costs
3. reduced transmission losses*
   - capacity benefit
   - energy cost benefit
4. lower transmission outage costs
5. value of reliability projects
6. value of mtg public policy goals
7. Increased wheeling revenues

Not quantified

8. reduced cost of extreme events
9. reduced reserve margin
10. reduced loss of load probability
11. increased competition/liquidity
12. improved congestion hedging
13. mitigation of uncertainty
14. reduced plant cycling costs
15. societal economic benefits

(SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

MISO MVP Analysis

Quantified

1. **production cost savings** *
2. reduced operating reserves
3. reduced planning reserves
4. reduced transmission losses*
5. reduced renewable generation investment costs
6. reduced future transmission investment costs

Not quantified

7. enhanced generation policy flexibility
8. increased system robustness
9. decreased natural gas price risk
10. decreased CO_2 emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

CAISO TEAM Analysis

(DPV2 example)

Quantified

1. **production cost savings*** and reduced energy prices from both a societal and customer perspective
2. mitigation of market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses*
7. emissions benefit

Not quantified

8. facilitation of the retirement of aging power plants
9. encouraging fuel diversity
10. improved reserve sharing
11. increased voltage support

(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity)

NYISO PPTN Analysis

(AC Upgrades)

Quantified

1. **production cost savings*** (includes savings not captured by normalized simulations)
2. capacity resource cost savings
3. reduced refurbishment costs for aging transmission
4. reduced costs of achieving renewable and climate policy goals

Not quantified

5. protection against extreme market conditions
6. increased competition and liquidity
7. storm hardening and resilience
8. expandability benefits

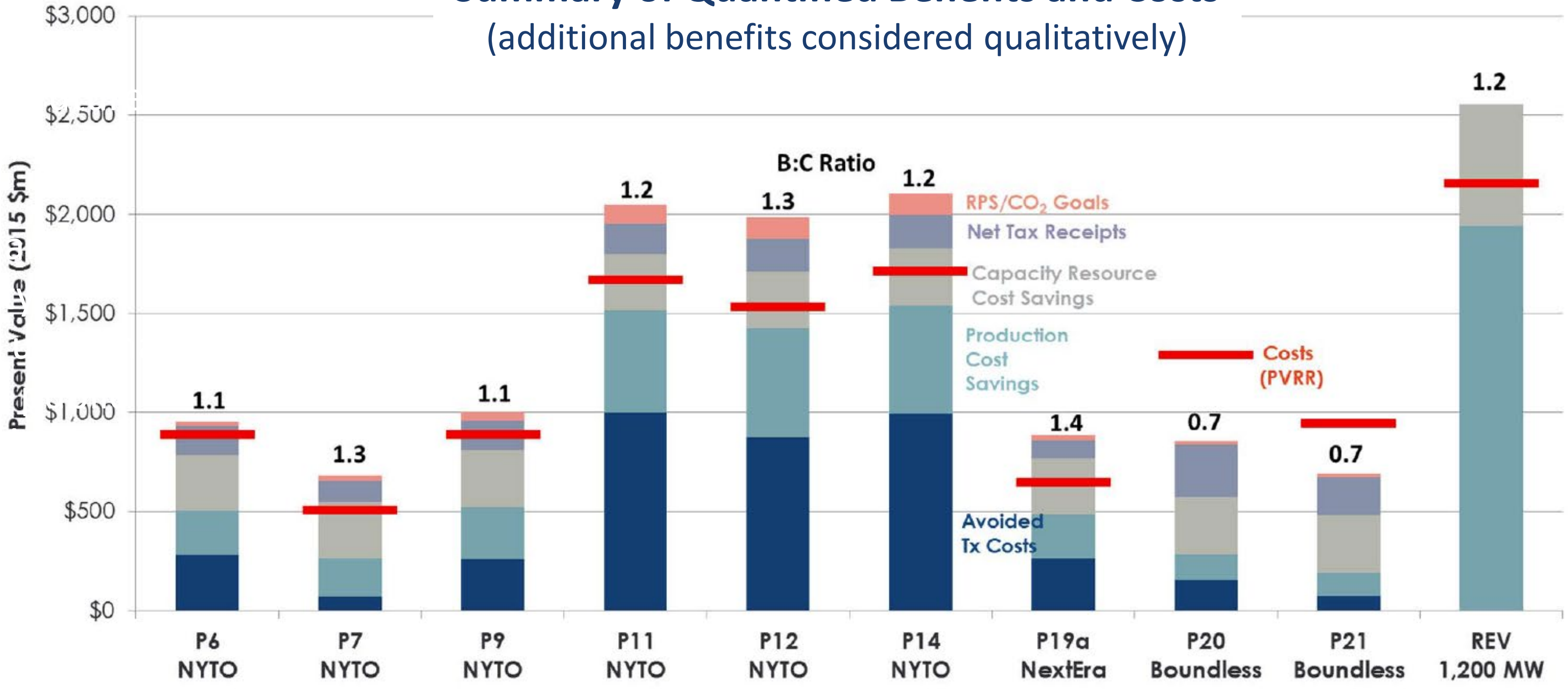
(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015)

* Fairly consistent across RTOs

New York's Multi-Value Transmission Planning Process

New York DPS modified its regional planning process by mandating that a **full set of benefits be considered**, resulting in approval and competitive solicitation of two major upgrades to the New York transmission infrastructure that have reduce costs across the state

Summary of Quantified Benefits and Costs
(additional benefits considered qualitatively)

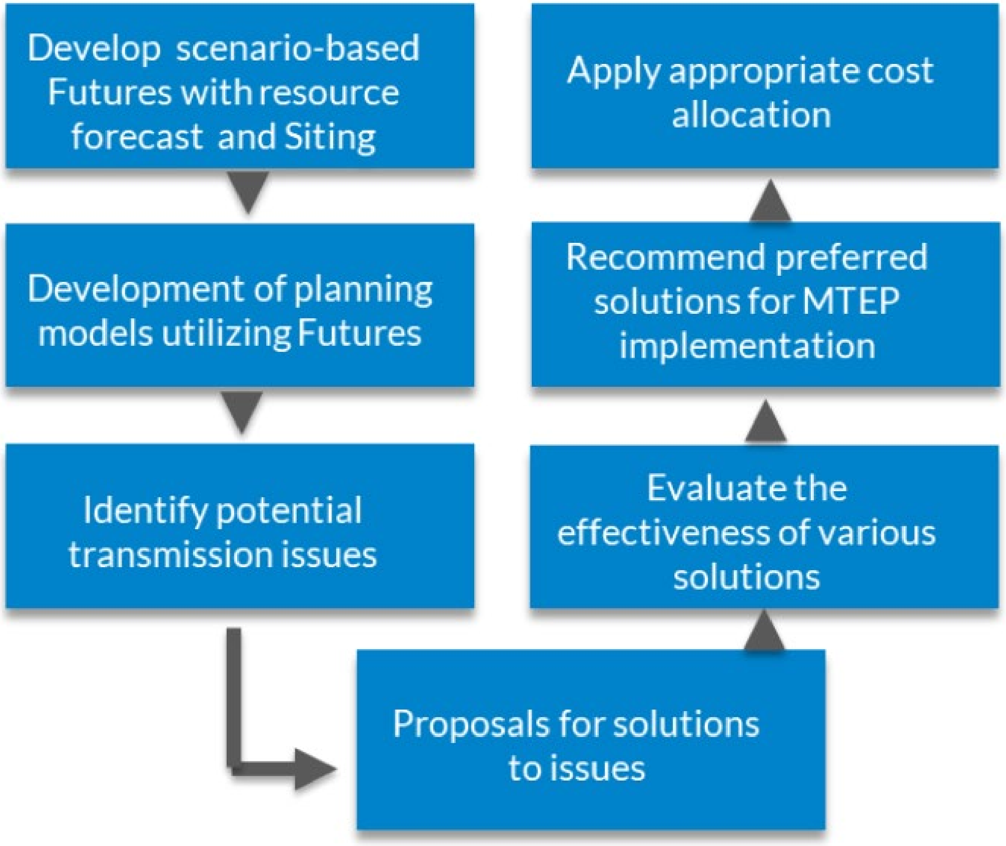


Source: "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," September 15, 2015

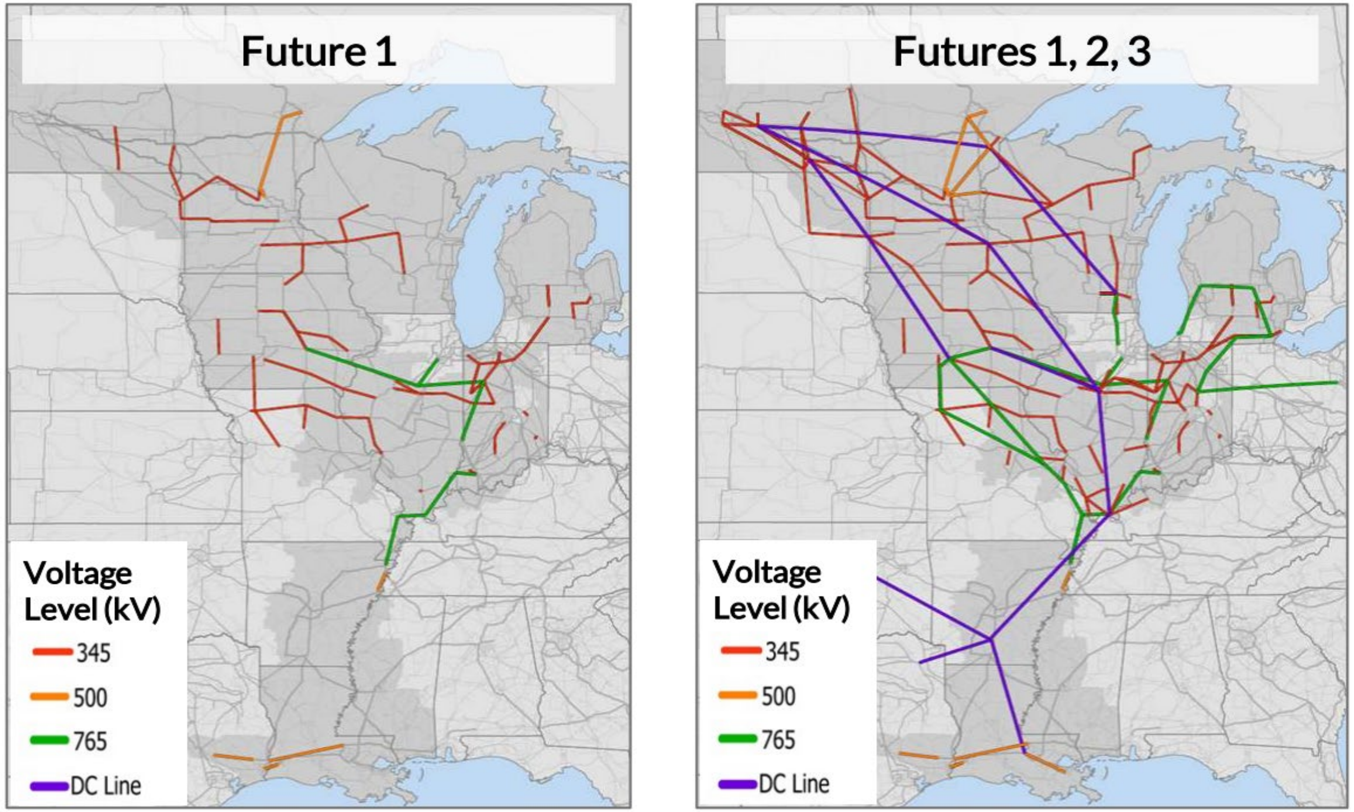
Example: MISO Long-Term Transmission Planning (LRTP)

MISO’s LRTP Tranche 1 and 2 efforts evaluated 20-year reliability, economic, and policy needs for a diverse set of plausible “Futures” (scenarios) that accounted for uncertainty in load growth and generation

MISO’s 2022 LRTP Process



MISO’s Identified Long-Term Transmission Needs



Source: MISO LRTP Roadmap March 2021

Example: MISO Long-Term Transmission Planning (LRTP)

Scenario-based LRTP resulted in a first tranche of a new "least regrets" portfolio of multi-value transmission projects (MVPs)

MISO 2022 LRTP RESULTS

- Tranche 1: $10 billion portfolio of proposed new 345 kV projects for its Midwestern footprint
- Supports interconnection of 53,000 MW of renewable resources
- Reduces other costs by $37-70 billion
- Portfolio of beneficial projects designed to benefit each zone within MISO's Midwest Subregion
- Postage-stamp cost allocation within MISO's Midwest Subregion

MISO 2022 LRTP, Tranche 1 Projects

Source: 3-29-22 LRTP Presentation (misoenergy.org)

Example: CTPC/Duke Multi-Value Strategic Transmission (MVST)

Carolinas Transmission Planning Collaborative (CTPC) completes local transmission planning for utilities in North and South Carolina, including Duke Energy (DEC/DEP), ElectriCities, and NCEMC

CTPC identified $503 million of Public Policy upgrades in its 2023 Annual Plan to support solar additions based on upgrades identified in multiple interconnection cluster studies

CTPC updated its local planning tariff to include MVST and is implementing the first MVST study:

- Modeling **3 future scenarios** based on Duke's projected load and IRP-developed generation portfolios
- Consideration of **GETs, advanced conductors, Remedial Action Schemes (RAS), and storage**
- Evaluation of a **portfolio of transmission upgrades** over the **full life of the assets**
- Quantifying **multiple benefits of transmission**: (1) avoided capacity costs, (2) capacity and energy savings from reduced losses, (3) congestion and fuel savings, (4) avoided customer outages, and (5) avoided transmission investment

Clarity in the face of complexity

Brattle

EXHIBIT 2

Akarsh Sheilendranath

Principal, The Brattle Group

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Mr. Akarsh Sheilendranath has over 15 years of experience within the power and utilities sector, having worked in economic consulting, at an independent system operator/regional transmission organization (ISO/RTO), and for regulated utilities. He specializes in the economic evaluation of wholesale electricity markets, transmission policy, resource planning, utility investment strategy, renewable generation procurements, energy storage valuation, cost-benefit assessments, market rules and tariffs, and the evaluation of cost of capital for regulated entities. He has advised a range of clients on these matters, including utilities, independent system operators (ISOs) and regional transmission organizations (RTOs), and utility commissions.

Mr. Sheilendranath has provided pre-filed and oral testimony in matters related to large-scale renewables investment, utility resource planning and reliability, transmission grid congestion risks, transmission market rule changes in ISO/RTO markets, and on cost of capital and return on equity matters for regulated utilities.

Prior to rejoining Brattle as a principal in 2024, Mr. Sheilendranath was a utility senior executive, employed as the director of the integrated resource planning and strategy group of American Electric Power Service Corporation (AEPSC). AEPSC provides planning, financial, accounting, and engineering advisory services to the eleven electric operating companies of American Electric Power Company, Inc. (AEP). Mr. Sheilendranath oversaw the planning and investment economics of regulated generation to support AEP operating companies, resource adequacy and capacity positions of AEP companies, innovation opportunities, and was involved in strategic decision making for AEP's regulated generation business. He advised transmission and policy groups and testified in company rate cases and integrated resource plan proceedings.

He has a dual specialization—in both the economics of generation and transmission grid investments, and in regulatory finance, including sponsoring expert testimony on return on equity estimation for Federal Energy Regulatory Commission (FERC) and state jurisdictional electric transmission, generation and distribution, water, and natural gas pipeline assets. He has testified on behalf of utilities, electric transmission and generation asset owners, and competitive electric market participants. He has advised his clients as well as ISO/RTOs and PUCs on the economics of transmission and large-scale renewable investments, renewable generation procurement, utility capacity planning and resource adequacy risks, cost of capital and return on equity estimations, designing public policy and competitive transmission procurement frameworks (now adopted by NYISO), and a spectrum of strategic business and policy decision making for transmission clients.

Akarsh Sheilendranath

Mr. Sheilendranath is experienced in regulatory finance and in the estimation of return on equity for regulated entities appearing before the FERC. He has sponsored expert testimony, assisted clients and counsel on deep strategic matters on settlement discussions, participated on FERC settlement calls on behalf of clients, and led the ROE estimation analyses for various transmission and pipeline projects. He is currently assisting several utility clients, including a FERC-regulated electric transmission company in the California ISO, and regulated electric utilities in the Southwest Power Pool, and PJM, in submitting expert testimony and analyses in separate state and FERC proceedings on the topics of return on equity estimation using the FERC's revised return on equity policy, and on the benefits of procurement of significant wind generation assets.

His testimonies have addressed risks, the effect of regulatory policies, such as must-run generation on a regulated company's cost of capital and the appropriate way to estimate the cost of capital for unique single-asset companies without access to capital markets, as well as electric cooperatives joining FERC-jurisdictional ISO/RTO markets. His clients are assisted by his deep understanding of the evolution of FERC's ROE policy both pre- and post- Opinion 531, and his significant knowledge of FERC's models and methodologies, its preferred sample selection criteria, and the commission's preferred use of various financial data sources for inputs to FERC ROE estimation assessment.

EDUCATION

Mr. Sheilendranath received an MBA from the New York University Stern School of Business, an M.S. in Electrical Engineering from Michigan Technological University, and a BS in Instrumentation Engineering from Siddaganga Institute of Technology.

TESTIMONIES AND SELECT ENGAGEMENTS

Resource Adequacy, Renewables, Cost Benefit Analyses, and Electric Transmission

- As one of AEP's two main witnesses, submitted direct, rebuttal, and sur-sur rebuttal testimony and testified before the Arkansas Public Service Commission (Docket No. 23-065-U) on matters related to the capacity position and resource adequacy needs & risks of the Arkansas jurisdiction of Southwestern Public Service Company, and the impact of John W. Turk Jr. Power Plant on said needs and risks, in the Company's application for a certificate of public convenience and necessity to operate the J.W. Turk, Jr. Power Plant, October 2023.
- Submitted expert testimony before the Arkansas Public Service Commission (Docket No. 19-035-U), the Texas Public Utilities Commission (Docket No.49737), the Louisiana Public Service Commission (Docket No. U-35324), and the Corporation Commission of Oklahoma (Cause No. PUD 201900048), Testimonies of Akarsh Sheilendranath in the Matter of the Acquisition of Wind Generation Facilities on behalf of Southwestern Public Service Company and Oklahoma Public Service Company, July 2019 through February 2020.
- Managed and co-authored the Initial Report on the New York Power Grid Study (January 19, 2021), which was prepared for the New York State Public Service Commission.
- Co-authored an extensive review of competitive transmission procurement practices of North American system operators and quantified the benefits of competitive transmission procurement.
- Developed various resource procurement strategies for American Electric Power (AEP), and analyzed the economic impacts of different resource procurement futures for AEP's operating companies in connection with AEP's Wind Catcher Project. His analyses for AEP included extensive assessment of potentially contracting with resource developers via PPAs, versus build-to-own models for the operating companies, to meeting their 25-year future energy and capacity needs.
- Provided strategic advisory services for AEP's leadership team in AEP's Wind Catcher Project development, and assisted the company on a range of issues, including ideation, regulatory approval processes, analysis of renewable PPAs, development of market simulations, and the design of benefit-cost frameworks to analyze the economics of integrating Wind Catcher's 2,000 MW of wind generating resources. These resources were delivered through a 765 kV generation tie line from the wind-rich Oklahoma Panhandle region to the company's load centers in Oklahoma, Arkansas, Louisiana and Texas.
- Provided strategic support in developing numerous renewable energy transmission investment options, valued between $0.5B-$2B, for the board of directors of a large utility in New England. Assisted in developing options to strategically align company's near-term growth opportunities with the long-term renewable vision of New England states and co-presented investment options and recommendations to the company's board of directors.
- Conducted benefit-cost analyses of New York Transmission Upgrades for the New York Public Service Commission, assisting New York's Department of Public Services (DPS) staff and the New York Independent System Operator in analyzing economic benefits of each of the proposed transmission portfolios. Worked with NY DPS staff to develop cost estimates and estimate revenue requirements for each proposed portfolio, and led the design and quantification analyses on the full-range of benefits of avoided transmission and reduced future transmission refurbishment assessments for each transmission portfolio.. See "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to

Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015.

- Led multiple stakeholder engagements on behalf of senior staff of ISO New England and the Southwest Power Pool (SPP), and presented analyses of long-range strategic planning for renewable futures, near-term market integration strategies, and cost-benefit assessments of regional public policy options.
- Worked with the Southwest Power Pool (SPP) and its committees in their efforts to develop planning approaches, assess benefits and cost allocations of SPP's $7 billion portfolio of transmission projects, and analyze benefit metrics and evaluation frameworks for interregional transmission projects. Presented study results and recommendations to various SPP Stakeholders on behalf of the SPP Staff.
- Represented ISO New England in the Department of Energy (DOE)-funded national planning coordination process, and presented ISO's strategic planning initiatives to the ISO board of directors and before various advisory committees.
- Analyzed merits and demerits of alternative transmission solutions to integrating large-scale offshore wind developments in the eastern US corridor for independent developers, and was a panelist and moderator for an offshore wind transmission conference panels on financing and the economics and viability of offshore grids.

Transmission Planning, Market Design, Public Policy and Strategic Planning

- Provided sworn Affidavit (with Johannes P. Pfeifenberger) before the Federal Energy Regulatory Commission, Docket No. EL19-34-000, on behalf of Brookfield Energy Marketing LP's complaint against PJM Interconnection, L.L.C. ("PJM") with respect to PJM's application of its changes to the Tariff and Reliability Assurance Agreement regarding pseudo-ties and their eligibility for participating in PJM's capacity market. Affidavit of Johannes P. Pfeifenberger and Akarsh Sheilendranath on behalf of Brookfield Energy Marketing LP's complaint against PJM Interconnection, L.L.C. ("PJM") with respect to PJM's application of its most recent changes to its Tariff and Reliability Assurance Agreement, January 18, 2019.
- Led multiple stakeholder engagements on behalf of senior staff of ISO New England and Southwest Power Pool (SPP), and presented analyses of long-range strategic planning for renewable futures, near-term market integration strategies and cost-benefit assessments of regional public policy options.
- Worked with the SPP and its committees in their efforts to develop planning approaches, assessing benefits and cost allocations of SPP's $7 billion portfolio of transmission projects, analyzing benefit metrics and evaluation frameworks for interregional transmission projects. Presented study results and recommendations to various SPP Stakeholders on behalf of the SPP Staff.

Cost of Capital, Utility Regulatory Finance and Recent Testimonies

- Submitted direct testimony on behalf of Rockland Electric Company concerning the cost of capital before the New Jersey Board of Public Utilities, May 2021.
- Submitted direct testimony on behalf of California Water Service Company concerning the cost of capital, Application No. 21-05, at the California PUC, May 2021.

- Submitted prepared direct and reply affidavit (with Michael Vilbert) on behalf of Constellation Mystic Power, LLC, Docket No. ER18-1639-000, on the cost of capital for the Mystic reliability must-run generation using the revised FERC ROE estimation methodology, September 2020, and October 2020. Testimony discussed the issue of risks for Mystic Power, and the estimation of the return on equity using the FERC's proposed revised ROE estimation methodology based on Opinion 569-A and its predecessor decisions.
- Submitted direct and rebuttal testimony (with Michael Vilbert) on behalf of Corn Belt Power Cooperative, Docket No. ER15-2028-002, on the cost of capital for the Cooperative using the revised FERC ROE estimation methodology and related ROE policy, March 2020.
- Submitted direct and rebuttal testimony (with Michael Vilbert) on behalf of Northwest Iowa Power Cooperative, Docket No. ER15-2115-003, on the cost of capital for the Cooperative using the revised FERC ROE estimation methodology and related ROE policy, February 2020.
- Submitted direct testimony before the Federal Energy Regulatory Commission, Docket No. ER19-2846-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE and capital structure to allow for its regulated electric transmission assets, September 2019.
- Submitted prepared affidavit and reply affidavit (with Michael Vilbert) on behalf of Constellation Mystic Power, LLC, Docket No. ER18-1639-000, on the cost of capital for the Mystic reliability must run generating using the revised FERC ROE estimation methodology, April 2019 and July 2019.
- Estimated the ROE using FERC methodology and developed direct testimony for a Brattle expert for submission at the FERC, Docket No. ER17-706-000 on behalf of Gridliance West Transco LLC, regarding Gridliance's application pursuant to section 205 of the Federal Power Act. Advised on the appropriate ROE, cost of debt, and capital structure to allow Gridliance to earn on the transmission facilities acquired from Valley Electric Association, December 2016. Assisted in Gridlinace settlement conference calls with the commission staff and the parties analyzed transmission incentives.
- Estimated ROE using FERC methodology and prepared a direct testimony and supporting exhibits for Brattle expert for submission before the Federal Energy Regulatory Commission, Docket No. EC17-049-000, on behalf of Gridliance West Transco LLC, regarding GridLiance's application pursuant to section 203 of the Federal Power Act (FPA) to acquire certain high voltage transmission facilities from Valley Electric Transmission Association, LLC (VETA), its parent non-profit electric cooperative, December 2016.
- Estimated the ROE using FERC methodology and developed direct testimony and supporting exhibits before the FERC, Docket No. ER16-2632-000. Worked on behalf of Trans Bay Cable LLC, regarding the appropriate ROE and capital structure to allow for its regulated electric transmission assets, provided long-term, continual strategic advisory support Trans Bay Cable's executives during the uncertainty surrounding the rate case as a result of the Opinion 531 remand. Assisted the client and its legal counsel on interrogatories and drafting of briefs, September 2016
- Led the estimation of a natural gas pipeline ROE using FERC's methodology and developed direct testimony for a Brattle expert for submission before the FERC, Docket No. RP17-598-000, on behalf of Great Lakes Gas Transmission Limited Partnership, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, March 2017.
- Led the ROE estimation analysis employing DCF, CAPM and risk premium financial models, and assisted in the preparation of direct and rebuttal testimony for Brattle's expert, for submission before the

Michigan Public Service Commission on behalf of the DTE Gas Company, Case No. U-18999, on the cost of common equity capital for DTE Gas Company's regulated natural gas distribution assets, February 2018.

- Led the ROE estimation analysis employing DCF and CAPM financial models, and assisted in the preparation of direct and rebuttal testimony for submission before the Michigan Public Service Commission on behalf of the DTE Gas Company (Case No. U-17799) on the cost of capital for DTE Gas Company's natural gas distribution assets, December 2015 and May 2016.
- Assisted in the ROE estimation analysis employing FERC's DCF methodology and led an economic conditions impact assessment in the preparation of direct testimony and supporting exhibits for submission before the FERC, Docket No. RP16-440-000, on behalf of ANR Pipeline Company, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, January 2016.
- For the Ontario Energy Board (OEB) staff, analyzed the appropriate capital structure for a power generator that engaged in a nuclear refurbishment program, and assisted Brattle expert submit evidentiary report advising the OEB Staff.

SELECT ARTICLES, REPORTS, AND PUBLICATIONS

- Initial Report on the New York Power Grid Study, prepared for the New York State Public Service Commission (with, J. Pfeifenberger, S. Newell, S. Crocker-Ross, Sharan Ganjam, Ric Austria, and Ketut Dartawan), January 19,2021.
- Integrating Renewables into Lower Michigan's Electric Grid: Resource Adequacy, Operational Analysis, and Implications, prepared for DTE Energy (with J. Chang, K. Van Horn, and J. Pfeifenberger), March 29, 2018.
- Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, prepared for LSP Transmission Holdings (with J. Pfeifenberger and J. Chang), April 2019.
- Transmission Solutions: Potential Cost Savings Offered by Competitive Planning Processes, prepared for LSP Transmission Holdings, GridLiance, presented at the 2018 National Association of Regulatory Utility Commissioners (NARUC) Annual Meeting (with J. Chang, and J. Pfeifenberger), November 13, 2018.
- Transmission Competition Under FERC Order No. 1000: What we Know About Cost Savings to Date, presented to WIRES (with J. Pfeifenberger, J. Chang), October 25, 2018.
- Transmission Competition Under FERC Order No. 1000 at a Crossroads: Reinforce or Repeal?, prepared for LSP Transmission Holdings, GridLiance, presented to American Public Power Association, 2018 L&R Conference, Charleston, SC (with J. Chang), October 10, 2018.
- U.S. Offshore Wind Generation and Transmission Needs, presented and moderated panel discussions at the 2nd Offshore Wind Transmission Conference New York, NY (with J. Pfeifenberger and J. Chang), September 17, 2018.
- Resetting FERC ROE Policy: A Window of Opportunity, Whitepaper & Presentation published by The Brattle Group, Inc., (with R. Mudge and F. Graves), May 2018.
- In the matter of: Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final

Report, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, presented to NYISO and DPS Staff, September 22, 2015.

- Lake Erie Market Assessment Report, prepared for ITC Lake Erie Connector LLC, (with J. Chang, J. Pfeifenberger), May 2015.
- Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, prepared for WIRES (with J. Chang and J. Pfeifenberger), April 2015.

EXHIBIT 3

Peter Heller

ENERGY RESEARCH ASSOCIATE

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Mr. Peter Heller specializes in design and implementation strategies for policy, regulation, and market design. At Brattle, Peter's work focuses on utility integrated resource planning, transmission planning and policy, and wholesale markets and planning. While pursuing his graduate degree at MIT, he focused on developing novel methods for measuring energy poverty across the United States and designing statutory and implementation changes to existing federal programs to enhance resource allocation. Prior to MIT, his work at the Colorado State Senate relied on meaningful stakeholder engagement and technical research to produce policy proposals related to decarbonizing the electric grid and moving the Western US towards an organized wholesale market for electricity.

EDUCATION

- **Massachusetts Institute of Technology**
  Master of Science in Technology and Policy
- **University of Colorado Boulder**
  Bachelor of Science in Environmental Engineering (*Summa Cum Laude*)

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2024–Present)**
  Energy Research Associate (2024–Present)
- **MIT Center for Energy and Environmental Policy Research (2022-2024)**
  Graduate Research Assistant
- **European Union Institute (EUI) Florence School of Regulation (2023)**
  Guest Lecturer and Course Assistant
- **Office of Senator Chris Hansen at the Colorado General Assembly (2021-2022)**
  Policy Director

ARTICLES & PUBLICATIONS

- "US federal resource allocations are inconsistent with concentrations of energy poverty," with Carlos Batlle, Christopher Knittel, and Tim Schittekatte, *Science Advances* (2024)
- "EU and US Approaches to Address Energy Poverty: Classifying and Evaluating Design Strategies," with Tim Schittekatte and Carlos Batlle, *MIT Center for Energy and Environmental Policy Research Working Paper Series* (2024)
- "Evaluating a Manhattan Project for Climate Change," with Nirmal K. Bhatt, *MIT Science Policy Review Vol. 4* (2023)
- "Modernizing the Western Grid: An Analysis of the Implementation of Regional Transmission Organizations in the Western US," with Chris Hansen, *Denver Journal for International Law & Policy* (2021)

PRESENTATIONS & SPEAKING ENGAGMENTS

- "Case example on vulnerable customers: the US and EU approaches to face the energy poverty challenge in the move towards decarbonization," Summer School on Regulation of Energy Utilities: Florence School of Regulation, Florence, Italy (July 2023)

SELECTED HONORS & AWARDS

2023	Dennis J. O'Brien USAEE/IAEE Best Student Paper Award
2020	Outstanding Undergraduate of the College of Engineering and Applied Science

COMMUNITY INVOLVEMENT

2024	SPARK Boston Council *South End Neighborhood Representative*
2023	MIT President Kornbluth's Presidential Advisory Cabinet *Board Member*
2023	MIT Technology and Policy Student Society *President*