Southern Renewable Energy Association
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May 2nd, 2025

VIA ELECTRONIC DELIVERY

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, S.W.
Atlanta, Georgia 30334

Re: Public Disclosure Direct Testimony and Exhibits on Behalf of Southern Renewable Energy Association in Docket No. 56002

Dear Ms. Tanner:

Please find enclosed the **Public Disclosure Direct Testimony and Exhibits of Alejandro Palomino on Behalf of the Southern Renewable Energy Association** to be filed in Georgia Public Service Commission Docket No. 56002 regarding Georgia Power Company's 2025 Integrated Resource Plan.

The Trade Secret version of this Direct Testimony is being filed separately pursuant to Rule 515-3-1-.11. Please contact me at (501) 701-0874 or whit@southernrenewable.org if you have any questions regarding this filing. Thank you for your assistance with this matter.

Respectfully submitted,

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Enclosures
cc: All parties of record in this docket (*via e-mail*)

STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	**)**	**Docket No. 56002**
2025 Integrated Resource Plan	**)**	

PUBLIC DISCLOSURE

DIRECT TESTIMONY OF ALEJANDRO PALOMINO

ON BEHALF OF

SOUTHERN RENEWABLE ENERGY ASSOCIATION

May 2, 2025

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1 Introduction

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS AFFILIATION.

A. My name is Alejandro Palomino (PhD), and I am a Senior Consultant at Energy Strategies LLC located at 111 East Broadway, Suite 1200, Salt Lake City, Utah 84111.

Q. PLEASE DESCRIBE ENERGY STRATEGIES' WORK.

A. Energy Strategies is an independent energy consulting firm founded in 1986. Our team includes economists, regulatory and policy experts, transmission engineers, power system modelers, and data scientists. Since its founding, Energy Strategies has supported utilities, developers, advocates and research organizations answer difficult questions around long-term capacity expansion and nodal production cost modeling, transmission and interconnection services, and energy markets and financial analysis.

Q. PLEASE STATE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked with various utility planning and operational models including PLEXOS and Aurora to conduct long-term capacity expansion (LTCE), production cost (PCM), and operational flexibility modeling. Most recently, my work at Energy Strategies has focused on utility integrated resource planning (IRP) proceedings. Since 2023, I have supported technical intervention on five integrated resource planning (IRP) processes across three states. In each of these proceedings, the utilities made their Aurora models available to participating stakeholders. My role in this work has been to evaluate utility assumptions, develop alternative scenarios, and evaluate their implications on the utility's resource plan.

Conducting this work through the utility's LTCE and PCM models offers these processes transparency, opportunities for collaboration and an exploration of diverse futures.

Before joining Energy Strategies, I worked as an electrical and controls engineering for Siemens Energy and then Duke Energy Commercial Renewables where I designed and monitored the remote operations systems for combined cycle and renewable energy facilities. I hold a bachelor's degree in mechanical engineering from the University of Florida and a PhD in electrical engineering from the University of Utah. I completed my doctoral program with a focus on power system economics, electric vehicle charging infrastructure and cyber-physical security. A copy of my current CV is attached as Exhibit AP-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN FRONT OF THE GEORGIA PUBLIC SERVICE COMMISSION

A. No.

Q. WHAT IS THE IRP?

A. The integrated resource plan (IRP) is published by Georgia Power Company (Georgia Power or the Company) to share their intended plans to serve the future needs of Georgia electricity consumers in accordance with their goals and requirements set by the public service commission. IRPs help to ensure utilities make prudent investment decisions that maintain reliability and preserve affordable rates while minimizing the societal harms of air, water and land pollution. Through this process, planners study a suite of future load, resource, cost, and constraint scenarios, build a resource plan based on study findings, and

publish the results to their regulating body. Critically, the IRP is a rare, semi-public process where ratepayers and advocates can provide alternative perspectives and comments on the plans published by their utility, a regulated monopoly. The process is effective when it enables utilities, regulators, and ratepayers to meaningfully participate in the future of their power system.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY?

A. I was retained by the Southern Renewable Energy Association (SREA) to evaluate Georgia Power Company's 2025 Integrated Resource Plan (IRP) modeling methods, best practices, and transmission plans. As a part of this evaluation, I identified opportunities for improvement in the Company's process and modeled alternative long-term capacity expansion (LTCE) scenarios to explore how select, key inputs drive resource planning and system performance. My testimony is organized as follows:

1. First, I will review the Company's base case MG0-111 scenario results and discuss their implications for the Company's resource action plan. Additionally, I will present alternative modeling results.
2. Second, I will review general best practices for integrated system planning and discuss how the Georgia Power IRP process can be improved to benefit transparency and accountability.
3. Third, I will discuss how conducting multi-scenario, multi-benefit, long-term transmission planning can benefit the Company and its ratepayers.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMISSION.

A. I recommend the Commission:

1. Require Georgia Power to expand their 2026 utility-scale renewables RFP to procure 2 GW of renewable energy resources by 2032.
2. Require Georgia Power to issue an additional RFP in 2026 for 2 GW of storage resources by 2032.
3. Require Georgia Power to demonstrate how its long-term capacity expansion modeling informs the timing, magnitude and composition of its resource planning and procurement efforts.
4. Direct Georgia Power to support a Transmission Working Group to conduct multi-scenario, multi-benefit, long-term (minimum 20-year) transmission planning in an open stakeholder process.

2 Review of the Company's capacity expansion plans

Q. BRIEFLY DESCRIBE GEORGIA POWER'S APPROACH TO LONG-TERM CAPACITY EXPANSION MODELING.

A. Georgia Power adopts the Southern Company system model to aid the development of their resource planning decisions. The Southern Company model comprises three operating companies and a wholesale electricity supplier. Within the model, existing resources are appropriately assigned to one of these four entities. Southern Company economically dispatches its assets as a single, unified system regardless of operating company ownership. Accordingly, the IRP model captures the entirety of the Southern Company system; all

loads, existing resources, resource candidates, and market purchase/sale actions. Build decisions resulting from long-term capacity expansion modeling are "generic" to Southern Company. The timing, magnitude, and composition of the resource planning decisions made by the model, the "generic" builds, are responsive to the Southern Company's total system needs.

Q. HOW DO THESE GENERIC BUILDS RELATE TO GEORGIA POWER?

A. The generic builds resulting from the model's long-term capacity expansion do not directly relate to Georgia Power's resource plans. In the model, new candidate resource builds are assigned to a generic operating company. Then, Georgia Power adopts a Resource Allocation Process through which they assign resource capacity from the generic build to individual operating companies. The allocation process begins with the system-wide generic builds. Then, given the total annual firm capacity of the generic build, resource-agnostic firm capacity is assigned to operating companies until an equal reserve margin is achieved across all operating companies and study years. From the resource-agnostic firm capacity, specific resources are allocated to operating companies by annual energy demand and resource assignment priority by capacity factor.

The Resource Allocation Process is not deterministic. The generic builds resulting from the long-term capacity expansion model do not filter down into individual operating companies according to a fixed equation. Instead, the process outlines an approach that assigns capacity by need and then rebalances across operating companies to achieve equivalent reserve margins.

Q. WHAT ARE THE IMPLICATIONS OF THIS RESOURCE ALLOCATION PROCESS?

A. The resource allocation process provides Southern Company with a buffer between the model results and their requests for new resource approval within the IRP. While Southern Company could explicitly model new resource builds in specific zones (representing operating companies) subject to interzonal transmission constraints, the resource allocation process enables Southern Company to more closely control where new candidate resources are allocated. Explicit modeling of new resources in specific zones could constrain Georgia Power's resource action plan to those resources built within Georgia Power zone.

Q. HOW DOES THE RESOURCE ALLOCATION PROCESS IMPACT THE TRANSPARENCY OF THE IRP PROCESS?

A. The current model setup used by Southern Company, along with its associated resource allocation process, obscures the extent to which the model influences Georgia Power's resource action plan. A long-term capacity expansion model specific to Georgia Power, or the adoption of a deterministic resource allocation approach, would enhance transparency by more clearly demonstrating how input assumptions drive the Company's resource build decisions across various scenarios.

Q. HOW DO THE RESULTS OF THE GEORGIA POWER ALLOCATION PROCESS RELATE TO THE ACTION PLAN DESCRIBED IN THE IRP?

A. It is unclear how Georgia Power's modeled long-term capacity expansion results guide the timing and magnitude of resource requests included in the action plan described in Chapter 8 of the IRP Main Document.

Q. WHAT IS INCLUDED IN GEORGIA POWER'S ACTION PLAN?

A. Georgia Power's supply-side strategy, or action plan, includes the extension of existing resources, upgrades to existing resources, modernization of hydro units, and changes to existing renewable energy procurement efforts. These requirements total 1,387 MW of thermal resource extension or upgrade, 665 MW of hydro modernization, utility-scale RFPs up to 4,000 MW of renewable energy resources by 2035 and 100 MW of distributed generation RFPs. Within the 2026 utility-scale RFP, Georgia Power has carved out 1,000 MW to be in service by winter 2032/2033. Taken together, these requests bring on approximately 3,200 MW of capacity by winter 2032/2033.

Q. WHAT IS GEORGIA POWER'S NEAR-TERM RESOURCE BUILD PLAN ACCORDING TO THE CAPACITY EXPANSION MODEL?

A. Georgia Power has adopted their MG0-111 long-term capacity expansion as their base scenario.[1] The first eligible year for new resources to be built in the model is 2028. Within the first five years of the MG0-111 model, 2028-2032, the Southern Company generic build

[1] Georgia Power 2025 IRP Main Document, Section 3.1 – IRP Process, at 18.

results in over 17 GW of cumulative capacity. More than 14 GW of the generic build is assigned to Georgia Power, or approximately 80% of the total. Of the 14 GW built in Georgia Power, the plan comprises 2.7 GW of CTs, 3.3 GW of combined-cycle CTs, 4.3 GW of solar, and 4.1 GW of storage (see Figure 1).

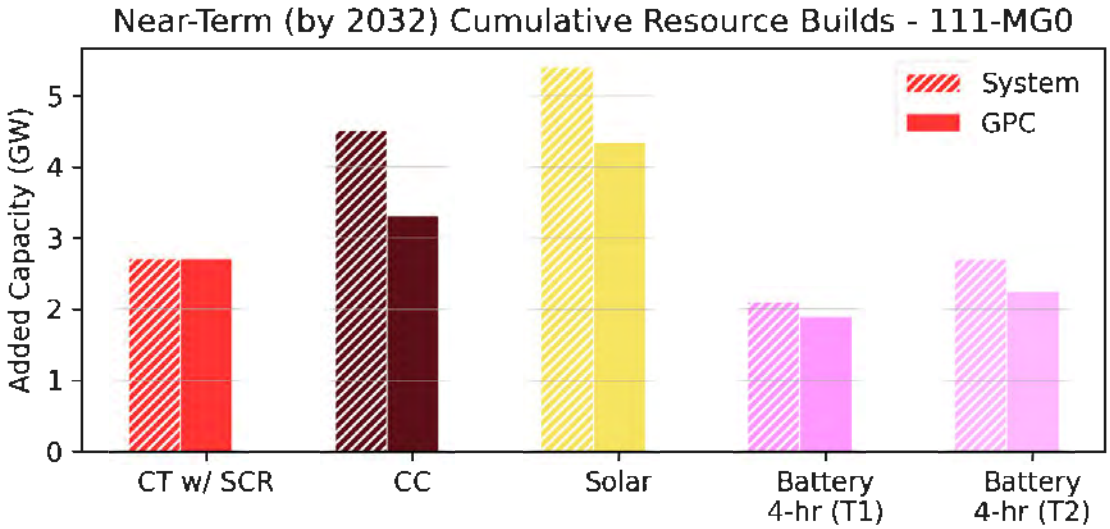


Figure 1: Near-term (by 2032) cumulative resource builds for MG0-111 scenario.

Q. HOW DOES GEORGIA POWER'S ACTION PLAN RELATE TO THESE MODELED LONG-TERM CAPACITY EXPANSION RESULTS? PARTICULARLY AS IT RELATES TO THE NEAR-TERM HORIZON?

A. The timing and magnitude of resources requests in Georgia Power's action plan does not directly relate to the optimal, long-term capacity expansion modeling results as defined in the Company's Capacity Expansion Plans included with the Resource Mix Study in Technical Appendix Volume 2 of the IRP. Instead, Georgia Power treats the generic

expansion plans as "indicative of what may be an optimal mix of resources within various scenarios."[2]

Recommendation: Georgia Power should demonstrate how its long-term capacity expansion modeling informs the timing, magnitude and composition of its resource procurement efforts.

The Company invests significant time and resources into developing the long-term capacity expansion model and scenarios as a part of the IRP. Sharing these models significantly benefits the transparency and accountability of the process, but the full benefit of working with optimized long-term capacity expansion modeling is limited when the empirical results of the model are not directly used or referenced in developing the Company's resource plan.

Q. BASED ON THESE MODEL OUTPUTS, WHAT WOULD YOU RECOMMEND REGARDING GEORGIA POWER'S NEAR-TERM RESOURCE PROCUREMENT?

A. I recommend the Company pursue more solar and storage resources. Analysis from a 2024 Lawrence Berkeley National Laboratory Report that battery storage resources present the greatest opportunity to bring firm capacity onto the system quickly.[3] Solar and storage investments are complementary. Additional storage capacity enables more low-cost solar

[2] Direct Testimony of Grubb, Hubbert, Looney, Robinson, Valle on Behalf of Georgia Power at 26 - line 7.
[3] Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 at 36 (April 2024), available at https://emp.lbl.gov/publications/queued-2024-edition-characteristics.

energy to be available on the system when it is most needed.[4] Georgia Power analysis in the 2025 IRP Technical Appendix Volume 2 Renewables Integration Study similarly highlights the complementary nature of solar plus storage in easing solar integration.[5] In testimony, witnesses for Georgia Power confirmed that significant increases can be made in solar penetration without negatively impacting system reliability. Further, flexible resources such as BESS can significantly reduce the cost of integrating renewables, reduce curtailments and improve system reliability.[6] Across the IRP's nine long-term capacity expansion scenarios, the average generic plan results in 3.3 GW of solar builds and 3.8 GW of 4-hr battery storage builds allocated to Georgia Power by 2032. Existing and proposed resource procurement plans by the Company do not reflect the scale of near-term solar and storage need.

Recommendation: Georgia Power should update its 2026 utility-scale renewables RFP to require 2 GW of capacity with commercial operation dates of 2032 or sooner.

Recommendation: Georgia Power should add a 2 GW storage RFP for projects with commercial operation dates of 2032 or sooner.

The recommendations for an acceleration of the 2026 utility-scale renewables RFP and the issuance of a dedicated storage RFP are conservative given the results of the Company's long-term capacity expansion modeling, which added over 3 GW of both solar and storage by 2032. Again, the development of these optimal long-term capacity expansion models

[4] Solar and Storage Integration in the Southeastern United States, Lawrence Berkeley National Laboratory at 22 (Sept 2024), available at https://emp.lbl.gov/publications/solar-and-storage-integration.
[5] Technical Appendix Volume 2, 2024 Renewable Integration Study at 28.
[6] Direct Testimony of Grubb, Hubbert, Looney, Robinson, Valle on Behalf of Georgia Power at 23 - line 3.

represents significant financial and labor investments from Georgia Power and its staff. The value of these investments is diminished if they do not directly inform the timing, magnitude and composition of resource procurement efforts.

Q. HOW DID YOU APPROACH ALTERNATIVE LTCE MODELING?

A. I started by reviewing Georgia Power's MG0-111 "base case" scenario model. Reviewing the model helped me understand Southern Company's existing fleet of resources, load trajectories, cost assumptions, operational constraints, and potential resource candidates. I then compared the inputs database to published IRP workpapers and finally executed a long-term capacity expansion run of Georgia Power's MG0-111 scenario, "out-of-the-box." The "out-of-the-box" run allowed me to benchmark my modeling environment with that of the Company.

Q. DOES GEORGIA POWER'S MODEL FAIRLY REPRESENT THEIR SYSTEM IN A MANNER THAT CAN ACHIEVE THE BEST RESOURCE PLAN FOR THEIR RATEPAYERS?

A. My review identified model features that diverge from current industry best practices and may steer outcomes away from the most cost-effective, reliable, and achievable resource plan that the Aurora long-term capacity expansion optimization software can identify. To unlock the full potential of IRP modeling, it is essential to give the optimization model a broad and flexible solution space. Doing so enables the model to identify the most cost-effective and reliable resource plan possible. This is a key best practice of IRP modeling.

The IRP planning process offers exactly the opportunity to test assumptions, make updates and add additional perspectives to the planning process.

Q. WHAT WERE THE FEATURES OR ASSUMPTIONS THAT YOU UPDATED IN YOUR MODELING?

A. I updated the following input assumptions, constraints and candidate resource costs in the development of our alternative modeling scenario.

1. Candidate Resource Accreditation

Winter continues to present the most significant reliability risks in Georgia Power's most recent Reserve Margin Study.[7] The Company asserts that it accounts for both summer and winter capacity contributions of resources in its assessment of capacity needs;[8] however, this approach is not extended to the Aurora LTCE model. Candidate resources in the Aurora LTCE model reflect only winter capacities. Accordingly, solar resource candidates are assigned a reliable capacity of 0%.

Georgia Power's 2022 IRP ELCC Study assigns utility-scale tracking solar resources a winter ELCC value of 5%, with higher values in non-winter months.[9] I input the seasonal ELCCs from the 2022 ELCC Study into the Aurora model as a monthly time series to best reflect the reliable capacity of wind and solar resources throughout the seasons. These monthly ELCC updates, in comparison to Georgia Power's out-of-the-box (OOB) model assumptions, are illustrated in the figure below.

[7] 2025 IRP Main Document, Section 6.1.1 – Seasonal Target Reserve Margins, at 39.
[8] 2025 IRP Main Document, Attachment C – Planned and Committed Resources, at 125.
[9] Docket # 44160, Georgia Power 2022 IRP, Doc. #188519, Technical Appendix Volume 1, *Study of Renewable Capacity Values using the ELCC Methodology in the Southern Company System* at 9, Table IV-1, December 2021.

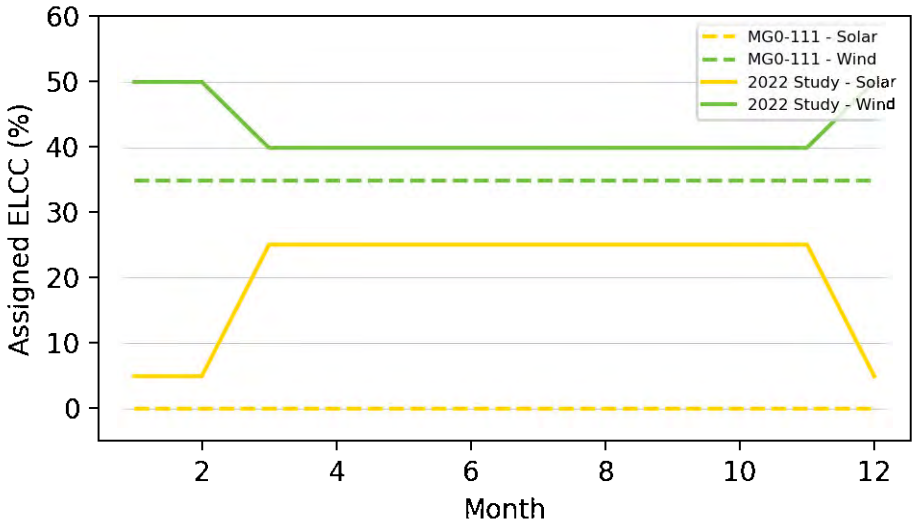


Figure 2: Seasonal resource accreditation values for wind and solar resources.

While the system is expected to endure greater reliability risks in the winter, a more accurate reflection of these weather-dependent resource's reliable capacity provides the model with the information it needs to consider the benefits of low-cost energy vs firm capacity when selecting candidate resources.

2. Renewable Energy Annual Build Limits

The wind and solar capacity expansion builds in the MG0-111 scenario are limited by the annual build limits in most years of the study. The 2025 Main IRP does not discuss the drivers for these annual build limits. The Resource Mix Study in Volume 2 simply states the annual build limits for wind and solar resources as 300 MW and 1.5 GW, respectively, but does not elaborate upon the reasons for these build limits. While it can be appropriate to adopt annual build limits to reflect a physical or development feasibility constraint, the IRP process would benefit from more transparency regarding these underlying factors.

When the built capacity hits the annual limit, it suggests that the system has a greater appetite, and therefore economic incentive, to build wind and solar capacity than is permitted by Georgia Power's adopted constraints. When this limit is encountered frequently, it merits additional scrutiny. Solar builds are constrained for four of the first five years of the build study horizon. After that, starting in 2033, both wind and solar builds are constrained by the annual build limit assumption. Annual wind and solar builds are illustrated as a percentage of annual build limits in the figure below. Stated differently, between 2033-2044, the model chooses to build the maximum amount of solar and wind resources that Georgia Power allowed in the model.

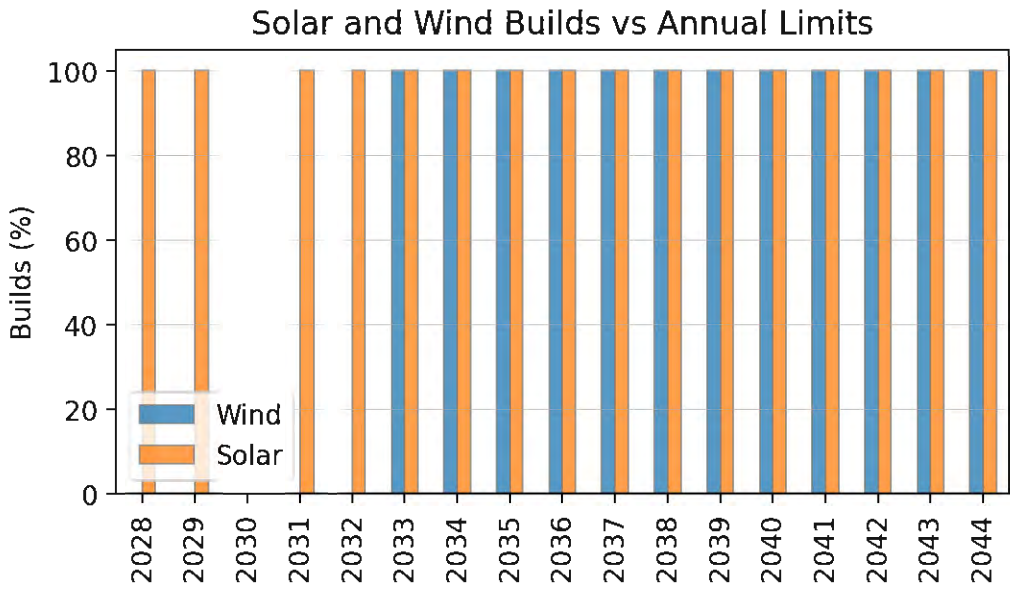


Figure 3: MG0-111 Wind and Solar builds as a percentage of build limits.

In order to test the robustness of this sensitivity, I doubled annual build limits for wind and solar to explore the boundaries of the model's appetite for those resources.

3. Combustion Turbine-based Thermal Resource Capitol Build Costs

Recent national studies and regulatory proceedings across the Southeast have underscored challenges in the procurement of combustion turbines, including prolonged order delays and sharp cost increases. The Company is aware of these procurement challenges and resulting costs. These dynamics underscore the urgency of proactive planning and diversified resource strategies.

The Louisville Gas and Electric Company and Kentucky Utilities Company (LGE/KU) 2024 Joint IRP estimate overnight capital costs of $1,846/kW and $1,424/kW for new combined cycle and combustion turbine units in 2024 dollars.[10] A 2025 IRP update from Dominion Energy South Carolina (DESC) projects combined cycle and combustion turbine costs on the order of $1,846/kW and $1,494/kW respectively.[11] Overnight capital costs are summarized below in comparison with Georgia Power's 2025 IRP assumptions.

Table 1: Thermal resource cost comparisons.

Source	1x1 Combined Cycle	Combustion Turbine
Georgia Power 2025 IRP[12]	$[redacted]	$[redacted]

[10] Kentucky Public Service Commission Case Number: 2024-00326, 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Volume 1 at 6-5, Table 6:4, available at https://psc.ky.gov/Case/ViewCaseFilings/2024-00326 (Costs in the LGE/KU reference are presented in 2030 dollars. $1,636 for simple-cycle combustion turbine and $2,121 for combined cycle units. Costs presented in testimony are deflated to 2024 dollars assuming 2.3% inflation.)

[11] DESC IRP Stakeholder Advisory Group Session XVI V, 2025 IRP Update at 33, available at https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_XVI.pdf. (The dollar year for costs presented are not explicitly stated.)

[12] Georgia Power 2025 IRP, Technical Appendix Volume 2, Southern Company 2025 Integrated Resource Plan Resource Mix Study (Trade Secret), Table 5: B2025 Technology Cost and Performance Summary, January 2025.

LGE/KU 2024 IRP	$1,846	$1,424
Dominion Energy South Carolina 2025 IRP Update	$2,453	$1,494

Testimony from Georgia Power's Director of Resource Planning Randy Hubbert confirms Georgia Power's awareness of these increased costs for gas-fired generators since the completion of the Resource Mix Study in the summer/fall of 2024.[13] While technology-specific assumptions and accounting approaches can impact how well these costs are accurately compared, the LGE/KU and DESC costs indicate Georgia Power's IRP assumptions [redacted] the capital costs associated with gas-fired generators, including 1x1 combined cycle units and combustion turbine units.

The IRP Process provides an opportunity to evaluate the implications of these costs on the optimal generic build. In recognition of the uncertainty underpinning these costs increases, I assume that spikes in combustion turbine-related capital costs will resolve by the mid-2030s. With these benchmarks in mind, I adopted combined-cycle resource costs of $2,000/kW and combustion turbine costs of $1,500/kW and then linearly scaled the resulting cost premiums down to zero over the resource's first five eligible build years.

Q. WHAT WERE THE RESULTS OF YOUR MODELING?

A. The alternative modeling scenario, called the "SREA Reference," realizes a generic system plan that differs from the results presented in Georgia Power's MG0-111 scenario.

[13] Georgia Power 2025 IRP March 25, 2025 Hearing Transcript at 513 - line 11.

Additionally, I modeled an alternative scenario based on the MG0-111 scenario, but only updated the combustion turbine-related resource overnight capital costs. This scenario approximates the MG0-111 scenario that Georgia Power itself would run given its admissions regarding the vintage of the resource cost assumptions. These model updates are summarized in the table below.

Table 2: SREA scenario definition summary

Scenario	Update Thermal Costs	Double Wind/Solar Annual Build Limits	Adopt Seasonal Resource Accreditation
MG0-111 with Updated CT/CC Costs	X		
SREA Reference	X	X	X

The cumulative near-term build results, by resource type, for the Company's MG0-111 scenario and SREA alternatives are illustrated in the figure below.

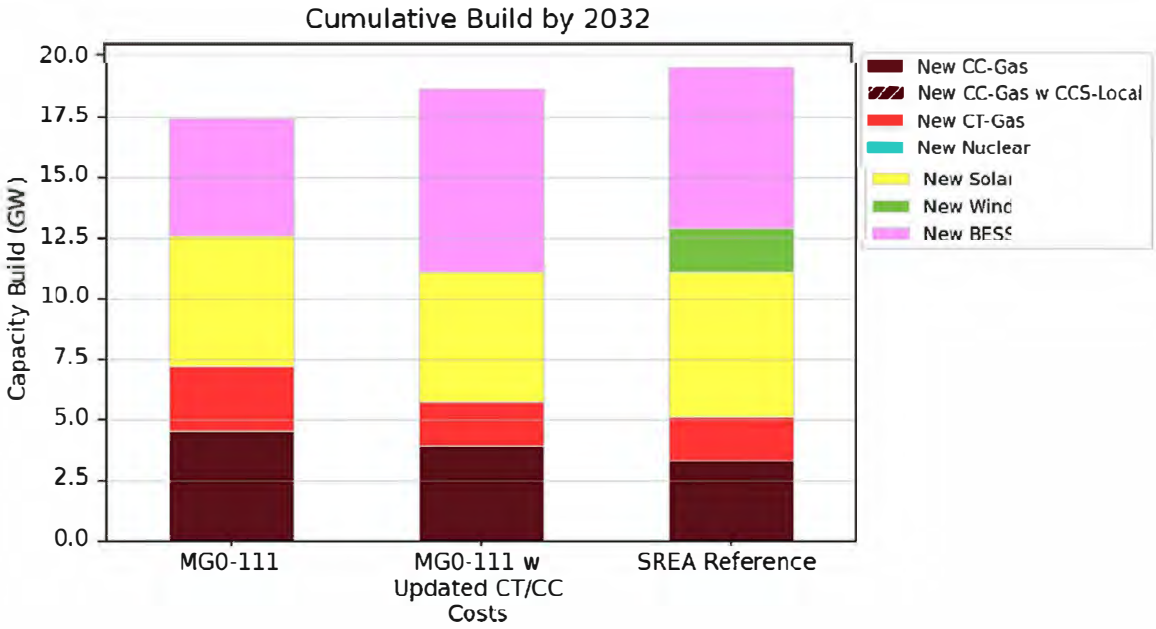


Figure 4: Alternative modeling near-term generic expansion plan composition.

I focused alternative modeling work on the near-term development that is most likely to impact the directives of this IRP. The cumulative builds are summarized in the following table. In the near-term, by the end of 2032, Georgia Power's MG0-111 generic system plan builds at least 3.3 GW of CC, 1.8 GW of CT, 5.4 GW of solar, and 4.8 GW of 4-hr BESS resources for all scenarios.

Table 3: Summary of cumulative near-term builds for SREA modeled scenarios.

Resource Build by 2032 (GW)	MG0-111	MG0-111 with Updated CT/CC Costs	SREA Reference
Combined Cycle Gas	4.5	3.9	3.3
Combustion Turbine Gas	2.7	1.8	1.8
Solar	5.4	5.4	6.0
Wind	0.0	0.0	1.8
Battery Storage	4.8	7.5	6.6

Q. HOW DOES YOUR ALTERNATIVE MODELING INFORM YOUR RECOMMENDATIONS?

A. Across Georgia Power's nine scenarios, the LTCE model identifies a near-term (by 2032) need for solar capacity of more than 3 GW on average. Similarly, the average near-term storage capacity need identified by the Company's LTCE scenarios is greater than 3 GW. My alternative modeling introduces two additional scenarios. Each identify greater than 5 GW of near-term solar need and greater than 6 GW of near-term storage need.

These results underscore recommendations 1 and recommendation 2 summarized at the end of this testimony. First, I recommend Georgia Power update its proposed 2026 utility-scale renewables RFP to require 2 GW of capacity with commercial operation dates of 2032 or sooner.[14] And second, I recommend Georgia Power add a 2 GW storage RFP in 2026 for projects with commercial operation dates of 2032 or sooner, in addition to the 500 MW ESS RFP that Georgia Power expects to issue in Q4 of 2025.[15]

[14] Georgia Power 2025 IRP Main Document at 67 (discussing Georgia Power's plans to "Issue 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.")

[15] Georgia Power IRP Main Document at 13 ("The Company expects to issue the 500 MW ESS RFP in Q4 2025 with expected certification from the Commission in Q3 2027.").

3 Review of Best Practices for Integrated System Planning

Q. PLEASE BREIFLY SUMMARIZE INDUSTRY BEST PRACTICES FOR INTEGRATED RESOURCE PLANNING.

A. My perspective on best practices for resource planning are well aligned with those in Lawrence Berkeley National Laboratory (LBNL) and Synapse Energy's *Best Practices in Integrated Resource Planning* report published at the end of 2024.[16] The report builds upon the collective expertise and experience of DOE researchers, public utility commissioners, technical consultants, and consumer and environmental advocates. Best practices for integrated resource planning involve (1) meaningful stakeholder engagement, (2) transparent model development built upon best available data and expertise, (3) balanced, multi-criteria evaluation of resulting portfolios, and (4) alignment of IRP model results with resource procurement plans.

1. A process with meaningful stakeholder engagement has two key components. First, it is a process that incorporates, or at minimum addresses, stakeholder feedback during model development, scenario design, portfolio evaluation, and creation of the resource procurement plan based on model results. Second the process should answer stakeholder questions in a manner and pacing that supports transparency within the timeline of the proceeding.

[16] *Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future*, Synapse Energy Economics Inc. and Berkeley Lab, November 2024, available at https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf.

2. Transparent model development in the IRP means stakeholders have access to the utility's resource planning model, accompanying software license, and input/output work papers necessary to benchmark the utility's results and develop alternative portfolios. To the benefit of public service commissions and ratepayers, neither of whom are likely to have all the relevant expertise to critically review the IRP, intervening stakeholders can test utility assumptions, identify opportunities for improvement, contribute additional expertise, and evaluate alternatives.
3. Multi-criteria evaluation should provide a holistic, empirical view of each resulting IRP portfolio to allow for a balanced comparison. At minimum, criteria should include a measure of system cost, fuel volatility risk, environmental impacts, and market exposure / reliability. IRPs should not rely upon single value portfolio scores based on an aggregation or weighting of constituent metrics as these approaches can obfuscate contributing factors and bias evaluation. Instead, IPRs should present unadulterated, empirical measures of metrics and allow regulators and stakeholders to evaluate portfolios on their merits.
4. Resource procurement plans – especially near-term action plans – should be clearly informed by the portfolio modeling results of the IRP. While resource planning is inherently complex and procurement decisions should not be based solely on model outputs, it is essential that utilities demonstrate a strong, transparent connection between modeling outcomes and procurement actions. Failing to do so risks undermining the credibility and effectiveness of the entire integrated resource planning process.

Q. HOW DOES GEORGIA POWER'S 2025 INTEGRATED RESOURCE PLAN COMPARE TO THESE BEST PRACTICES?

A. First, the IRP process in Georgia does not meaningfully engage stakeholders in the initial modeling process before the IRP is filed. A robust and effective IRP process involves three key phases of stakeholder involvement: early participation in model development and scenario design, midstream input on preliminary modeling and proposed sensitivities, and final feedback on published results and their implications for resource planning. Meaningful stakeholder engagement can aid the Commission in their efforts to cultivate a transparent and accountable IRP process that best supports all of Georgia's ratepayers.

Georgia Power's current approach limits stakeholder involvement to the final phase, after modeling is complete and decisions are largely set. This approach excludes critical, independent review at the stages when it could most improve model accuracy, transparency, and responsiveness to ratepayer needs. Georgia Power's lack of early and substantiative stakeholder engagement results in a less inclusive and credible process that is potentially misaligned with public interest.

Q. WHAT ARE YOUR RECOMMENDATIONS TO IMPROVE THE IRP PROCESS IN GEORGIA?

A. I have four main recommendations for improving the IRP process in Georgia, as explained below.

First, the IRP process in Georgia does not meaningfully engage stakeholders. A robust and effective IRP process involves three key phases of stakeholder involvement: early

participation in model development and scenario design, midstream input on preliminary modeling and proposed sensitivities, and final feedback on published results and their implications for resource planning. Georgia Power's current approach limits stakeholder involvement to the final phase, after modeling is complete and decisions are largely set. This approach excludes critical, independent review at the stages when it could most improve model accuracy, transparency, and responsiveness to ratepayer needs. Georgia Power's lack of early and substantiative stakeholder engagement results in a less inclusive and credible process that is potentially misaligned with public interest.

Process Improvement 1: The IRP process would be improved by the addition of a resource planning advisory committee made up of stakeholders to provide feedback and additional perspectives to the company throughout the development of the IRP.

Second, the IRP process falls short of transparency best practices. Although Georgia Power provided its input workbooks, IRP model, and an Aurora software license, the process lacks a formal discovery mechanism. Without it, stakeholders must depend entirely on Public Service Commission Staff to raise questions or request clarifications from the utility. Given the inherent complexity of IRPs, this limited access creates significant uncertainty. Even with access to the model and workpapers, critical assumptions and methodological choices remain opaque—undermining stakeholders' ability to accurately replicate, evaluate, or challenge the utility's modeling results. Stakeholders must then weigh the costs and benefits of pursuing data requests through commission staff against primary due diligence work on the IRP weakening stakeholder participation.

Process Improvement 2: If formal discovery is not feasible, Georgia Power should host IRP forums for stakeholders to ask questions on a schedule that supports meaningful engagement.

Third, the IRP process does not employ a multi-criteria approach to evaluate scenario portfolios. Resource selection and summary metrics are very limited in the Georgia Power IRP. Within the IRP Main Document, Georgia Power provides only the cumulative generic resource plans[17]. In Technical Appendix 2 – Capacity Expansion Plans, Georgia Power provides total system cost by scenario. Otherwise, Georgia Power does not provide any metrics or summary results with which stakeholders or commissioners can evaluate the relative "goodness" of individual scenario portfolios. Metrics for environmental sustainability, resource performance, and market reliance are not provided. Further, Energy Exemplar, the manufacturer of the Aurora resource planning software, recommends that operational metrics (e.g. those reliant on hourly dispatch) not be measured from sampled long-term capacity expansion (LTCE) model runs. Relying on sampled chronologies can provide unreliable summary metrics. Instead, such metrics should be drawn from hourly production cost modeling runs to ensure accuracy. It is not clear from the materials shared by Georgia Power that any production cost modeling runs where conducted for the main resource expansion scenarios as part of the IRP. In short, the data shared by Georgia Power to stakeholders makes it impossible to verify the costs of their resource portfolios.

Process Improvement 3: Georgia Power should develop and utilize a criterion to evaluate the performance of each portfolio using long-term capacity expansion and production cost modeling results.

[17] 2025 IRP Main Document, Figure 8.9B: B2025 Generic Expansion Plan Results (2025-2044), at page 75

Finally, Georgia Power's resource procurement plans are disconnected from the results of their IRP modeling—a disconnect evident in Ch. 8 Supply-Side strategy of IRP Main Document. There, Georgia Power seeks approval for its proposed action plan before presenting the outcomes of its capacity expansion modeling, undermining the integrity of the process. In my experience, utilities first present detailed, incremental resource buildouts from the LTCE modeling—by year, capacity, and technology type—and then used those results to shape a procurement plan that reflects the modeled outcomes. This sequence builds trust that procurement decisions are rooted in a transparent, data-driven. Georgia Power's reversal of that sequence raises serious concerns about the role of modeling in guiding actual resource decisions. I recommend Georgia Power demonstrate how its long-term capacity expansion modeling informs the timing, magnitude and composition of its resource procurement efforts.

Q. DO YOU HAVE ANY COMMENTS ON GEORGIA POWER'S EXISTING APPROACH TO RENEWABLE ENERGY RESOURCE PROCUREMENT?

A. Yes. I support the Company's efforts to increase flexibility in their RFP processes.

Q. DO YOU AGREE THAT "GEORGIA POWER'S RFPS MUST BECOME MORE FLEXIBLE AND ADAPTABLE TO CAPTURE THE VALUE THAT RENEWABLE RESOURCES CAN OFFER TO CUSTOMERS?"[18]

A. Yes. Georgia Power acknowledges that the 2023/2024 Utility Scale RFP did not yield any qualifying bids due to challenging market conditions.[19] Increasing the capacity targeted in procurement via RFPs is only part of the solution to effectively increasing procurement of renewable energy resources to serve Georgia Power's customers. If the details of the RFP process and corresponding power purchase agreements are not financially viable (i.e., bankable) to renewable energy project developers (i.e., SREA's members) and their investors, the Commission cannot reasonably expect Georgia Power to be successful in procuring the targeted amounts. Therefore, Georgia Power must also improve its RFP process to ensure that the process is effective and successful in actually procuring the targeted amounts.

Q. DO YOU SUPPORT GEORGIA POWER'S PROPOSED "ENHANCEMENTS" TO THE CARES PROGRAM, INCLUDING THE RFP CHANGES AND ADDITIONAL CUSTOMER SUBSCRIPTION OPTIONS?

A. Yes, for the most part. Although this is not the primary focus of my testimony, I generally agree that most of Georgia Power's proposed "enhancements" will help to increase

[18] Direct Testimony of Dr. Ross Beppler, Carley Goff, A. Wilson Mallard, and Andy Phillips on behalf of Georgia Power at 27, Docket Nos. 56002 & 56003.
[19] IRP Main Document at 79, 8.11.3 – Utility Scale RFPs.

opportunities for project selection and procurement to meet customer renewable subscription needs."[20] Some of the enhancements that I support include the following:

- adding flexible Required Commercial Operation Dates (RCODs), allowing projects to have a wider range of acceptable in-service dates and enabling RFP participants and the Company to navigate market challenges such as supply chain disruptions and changing policy landscapes,[21]
- offering extended RFP periods with a customer identified resource option, whereby customers would have the option to propose specific renewable resources for procurement, negotiating directly with developers, and
- the ability to subscribe to incremental resources at higher subscription prices that offset higher PPA costs.[22]

Q. WILL THE ENHANCEMENTS PROPOSED BY GEORGIA POWER "MAXIMIZE OPPORTUNITIES FOR PROJECT SELECTION AND PROCUREMENT TO MEET CUSTOMER NEEDS."[23]

A. "Maximize" is very strong word. While many of the proposed enhancements should have the effect of increasing opportunities for project selection and procurement to meet customer needs, there are still opportunities for further enhancements, as noted in Georgia Power's testimony.[24] Therefore, I would not agree that the opportunities for enhancing the

[20] *Id*. at 7.
[21] *Id*. at 27.
[22] *Id*. at 37; IRP Main Document at 80, 97
[23] *Id*. at 27.
[24] *Id*. at 26. ("Through market interaction and recent RFP experience, the Company has identified several challenges and opportunities that necessitate modifications to further enhance its procurement processes.").

RFP process and available customer options for accessing renewable energy have been fully maximized by Georgia Power's proposals in this IRP. While Georgia Power's proposed enhancements are generally a step in the right direction, there is still room for improvements.

Q. WHAT OPPORTUNITIES ARE AVAILABLE TO IMPROVE THE CIR OPTION AND FULLY CAPTURE THE VALUE THAT RENEWABLE RESOURCES CAN OFFER TO CUSTOMERS?

A. Regarding the CIR option, I encourage the Commission to consider the following recommendations that are set forth in the testimony by the Clean Energy Buyer's Association:

- The Commission should direct Georgia Power to allow large customers to bring forward Customer Identified Resources on a rolling basis after the conclusion of this IRP, or, in the alternative, direct Georgia Power to initiate its proposed Phase II process to procure Customer Identified Resources as part of the ongoing 2023 CARES RFP or the upcoming 2025 CARES RFP.

- The Commission should direct Georgia Power to allow multiple customers to coordinate to bring forward and subscribe to a single Customer Identified Resource.

- The Commission should approve Georgia Power's proposal to allow customers to negotiate directly with developers or to sign subscription agreements with higher prices to offset higher PPA costs for Customer Identified Resources.

In general, the Commission should endeavor to remove any unnecessary barriers that arbitrarily limit customer options for accessing renewable energy.

Q. ARE THERE ANY OTHER UNNECESSARY BARRIERS THAT THE COMMISSION SHOULD CONSIDER REMOVING TO INCREASE CUSTOMER ACCESS TO RENEWABLE ENERGY AND FULLY CAPTURE THE VALUE THAT RENEWABLE RESOURCES CAN OFFER TO CUSTOMERS?

A. Yes. My understanding is that guidance from the Georgia Public Service Commission has historically recommended that Georgia Power own 70% of the generation resources in its portfolio, and notify the Commission when they exceed 30% for PPAs.[25] I recommend that the Commission consider revising this policy to allow more PPAs.[26] This would allow SREA's members more opportunities to deliver low-cost renewable energy to Georgia Power's customers. As was further discussed in SREA's testimony regarding Georgia Power's 2023 IRP Update, it is common practice for utilities in vertically integrated markets to maintain less than 60% ownership of generation resources, and there is no evidence that suggests reliability is impacted due to a lower prevalence of utility-owned generation.[27]

[25] *See*, GPSC Docket No. 55378, Direct Testimony of Arne Olson at 35, FN 43 (citing Transcript of January 16, 2024 Hearing at 359-360).
[26] *Id*. at 35-37.
[27] *Id*. at 37.

4 Review of Company's Transmission Plan within the IRP Context

Q. HOW DOES GEORGIA POWER ADDRESS TRANSMISSION PLANNING IN THE IRP PROCESS?

A. The IRP model and resulting resource expansion plans do not factor in transmission.[28] Transmission implications and any downstream planning requirements are addressed in resource RFPs. Chapter 11 of the 2025 IRP Main Document outlines Georgia Power's transmission planning principles, ten-year plan and strategic transmission projects.

Q. HOW DOES GEORGIA POWER APROACH TRANSMISSION PLANNING?

A. Georgia Power's approach to transmission planning is detailed in Technical Appendix Volume 3 – Transmission Plan. Georgia Power plans its transmission system as part of the Integrated Transmission System (ITS) consisting of transmission facilities in Georgia. ITS Participants coordinate loads, resources and system changes to make updates to the transmission system models. They then conduct transmission load flow and stability models to explore transmission needs on the system in response to load growth under various conditions. From these needs, the ITS planners develop transmission solutions, remove infeasible solutions and then evaluate the net-benefit of remaining solutions.

Q. WHAT ARE TRANSMISSION PLANNING PRIORITIES OF THE ITS?

A. The planning priorities of the ITS center on system reliability, operational resilience, deliverability costs and risks, and economic timing of transmission expansion projects. The

[28] Georgia Power 2025 IRP March 25, 2025 Hearing Transcript at 503 - line 18.

ITS identifies potential solutions for the ability to resolve thermal and voltage problems. Based on these planning principles and the feasible solutions identified in the ITS transmission system model, Georgia Power develops a strategic ten-year plan.[29]

Q. WHAT STRATEGIC TRANSMISSION PROJECTS WERE IDENTIFIED IN THE 2025 IRP?

A. The ten-year plan includes 23 projects spanning in-service dates of 2025 to 2033. Per the 2025 IRP Technical Appendix Vol. 3 Transmission Plan, many of these projects serve more than one transmission planning objective. Of these projects, the vast majority, 19, seek to improve system reliability. Four projects seek to mitigate load growth challenges, four projects are driven by changes in system flows, and three projects support solar and renewable generation flows.

Q. DOES GEORGIA POWER ADOPT A MULTI-BENEFIT CRITERIA WHEN EVALUATING STRATEGIC TRANSMISSION PROJECTS?

A. Georgia Power's transmission planning process is primarily focused on evaluating a project's ability to address thermal and voltage constraints. Still, many of the strategic transmission investments identified in the Company's ten-year plan provide more than reliability benefits.[30] These additional benefits highlight the complementary nature of transmission expansion on the system.

[29] 2025 IRP Main Document, Table 11.3 – Strategic Transmission Projects, at page 113
[30] Technical Appendix Volume 3, Section 10 – Georgia Power Company Transmission Planning Process, at page 36

Q. WHAT OTHER BENEFITS CAN BE REALIZED BY TRANSMISSION EXPANSION?

A. Beyond ensuring reliability and resilience, transmission expansion enables load growth, streamlines resource interconnection, and lowers costs by reducing losses, easing congestion, and integrating more low-cost, non-emitting generation. By adopting a multi-value criterion for strategic transmission planning, Georgia Power can maximize long-term system benefits as it confronts significant load growth and evolution of its resource generation mix.

Q. HOW CAN GEORGIA POWER REALIZE THESE BENEFITS IN THEIR TRANSMISSION PLANNING?

A. I recommend Georgia Power pursue a multi-value strategic transmission study approach. At minimum, the approach should evaluate additional economic and reliability benefits not currently covered by the transmission planning process over a study horizon of at least 20 years to support long-term regional transmission facilities. A side-by-side comparison of existing and potential benefits is summarized in the table below.

Table 4: Transmission Benefits Criteria Comparison

Existing Georgia Power Benefit Criteria	Additional Multi-Value Criteria
• Resolution of thermal constraints • Resolution of voltage constraints	• Avoided capacity costs • Reduced losses • Reduced congestion • Fuel Savings • Production Cost Savings • Avoided Customer Outages

- Avoided Transmission Investments

Q. WHAT ADDITIONAL BENEFITS ARE NOT CAPTURED BY GEORGIA POWER'S TRANSMISSION PLANNING PROCESS?

A. Georgia Power's Planning Guidelines, as part of the ITS, follow planning objectives outlined by NERC Reliability Standards TPL-001. These objectives are centered around reliability requirements, such as thermal and voltage constraints, and broader operational implications, such as economic dispatch under altered system conditions and variable energy resource impacts.

Georgia Power's Planning guidelines do not include benefits such as avoided capacity costs, capacity savings from reduced losses, congestion and fuel savings, energy savings from reduced losses, avoided customer outages, and avoided transmission investments. By considering these benefits, Georgia Power can proactively identify transmission solutions that support the load growth and generation additions sought as a part of the 2025 IRP while making the system more resilient to extreme events.

Q. HOW MIGHT THE INCLUSION OF THESE ADDITIONAL BENEFITS IMPACT GEORGIA POWER'S SYSTEM?

A. The pooling arrangement under which Southern Company economically dispatches the resources of its operating companies, Georgia Power, Alabama Power and Mississippi Power, results in a more reliable system with lower overall system production costs.[31] The

[31] 2025 IRP Main Document, Attachment G.4 – Basic Principles of the IIC, at 146.

operational benefits realized by Southern Company and its constituents through pooling can be enhanced by a multi-value study approach to transmission planning. By including additional benefits, Georgia Power can identify and develop transmission projects that improve system liquidity, load diversity and resource diversity. In the event of extreme weather, a transmission system that better leverages regional diversity in the Southern Company portfolio will better withstand outages and keep the lights on for Georgia ratepayers.

Q. CAN YOU ELABORATE ON GEORGIA POWER'S PERFORMANCE UNDER EXTREME WEATHER EVENTS?

A. Yes. In December 2022, the southeast suffered a significant winter storm event that placed severe stress on the region's grid. Winter Storm Elliot caused rolling outages in TVA, LG&E/KU, PJM and the Carolinas and highlighted the risks of correlated gas outages in the southeast.[32] While Georgia Power, and Southern Company more broadly, were able to avoid outages, their gas fleet similarly suffered significantly elevated forced outages. Solar resources on the other hand, performed above expectation for a winter event.[33] Additional storage on the system would help to firm solar capacity for periods of greatest need and transmission expansion that values these benefits could make more of these resources available to the broader system. Regional and interregional transmission expansion can

[32] Winter Storm Elliot Event Analysis and Recommendation Report PJM (July 2023) available at https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ at 49.

[33] Winter Storm Elliot An Independent Review of Southern Company's Performance During the Historic Events of December 22 – 25, 2022 (2024) at 16, available at https://southernrenewable.org/news-updates/winter-storm-elliott-reviewing-how-the-grid-performed-across-the-southeast-during-an-extreme-weather-event. (Exhibit AP-2).

mitigate reliability risks by providing Georgia Power access to low cost and uncorrelated resources in other regions.

Ultimately, a transmission planning approach that values benefits beyond thermal limits and voltage constraints will reduce production costs, place downward pressure on reserve margins, improve renewables integration and enhance resilience. A multi-value criterion ensures that transmission planning reflects the real-world complexity and opportunity of Georgia's evolving grid. It encourages more stakeholder engagement and more efficient investment decisions.

Q. WHY SHOULD THESE BENEFITS BE STUDIED OVER A LONG HORIZON?

A. Georgia Power's current transmission planning process, as part of the ITS, plans strategic transmission projects to resolve reliability deficiencies as identified by NERC Reliability Standards TPL-001.[34] The TPL-001 requires transmission planning studies be completed to cover near-term (1-5 year) and long-term (6-10 year) horizons.

New transmission projects, particularly regional and interregional projects, often require significant lead-time to plan, develop and construct. A longer-term planning view, of at least 20 years, will enable Georgia Power and ITS participants to better anticipate future needs, evaluate reliability and economic benefits, and appropriately allocate costs for these interjurisdictional investments. Additionally, with at least a 20-year transmission planning horizon, Georgia Power can better align planning efforts with the operational life of resource and transmission assets. The Southwest Power Pool, by way of example, requires

[34] Technical Appendix Volume 3, B2 – Georgia ITS Transmission Planning Guidelines, at PDF 45.

that the financial benefits of new transmission lines be evaluated over a 40 year horizon and consider "dispatch savings, loss reductions, avoided projects, applicable environmental impacts, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics as appropriate."[35]

I concur with testimony by Georgia Power witnesses on the importance of an "extended horizon," "additional planning considerations" and "process enhancements" when conducting their future strategic transmission planning.[36] These process enhancements should support with many of the best practices outlined in this section.

Recommendation: I recommend Georgia Power develop and adopt a long-term, multi-value study approach to joint transmission planning with its neighboring operating companies that meaningfully engages stakeholders.

Q. ARE THERE EXAMPLES OF THIS KIND OF HOLISTIC PLANNING IN PRACTICE TODAY?

A. Yes. The Carolinas Transmission Planning Collaborative (CTPC) offers a model for collaborative, regional transmission planning. The CTPC was formed in 2005 to support the development of a shared transmission plan across North and South Carolina.[37] The Collaborative adopts a multi-value strategic transmission study approach that builds on

[35] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1, available at https://www.efis.psc.mo.gov/Document/Display/86742, at 15.
[36] Direct Testimony of Grubb, Hubbert, Looney, Robinson, Valle on behalf of Georgia Power Company, at 38 – 39.
[37] NCTPC Press Release March 2024, 2023 Collaborative Transmission Plan available at: 2024 NCTPC Press Release 03222024_Final.pdf.

local plans and incorporates stakeholder input. The approach explores future scenarios, identifies potential challenges and solutions, and recommends a balanced transmission plan that weighs costs, benefits, and risks. Stakeholder participation is solicited via the CTPC Transmission Advisory Group (TAG) whereby support the development of annual work plans, study design, and providing recommendations to the Oversight Steering Committee (OSC).

The results of the most recent CTPC Collaborative Transmission Plan, the 2023 Plan, estimates $2.44B in transmission investments spanning 58 reliability driven projects and 15 projects driven by public policy. Both reliability and public policy projects are subject to the same benefit-cost criterion. Those projects included in the 2023 Plan reflect a net-benefit to the system. The plan highlights the fundamental role of transmission expansion in maintaining system reliability while recognizing cost and emissions impacts that can benefit Georgia ratepayers.

Q. DOES GEORGIA POWER PARTICIPATE IN ANY OTHER TRANSMISSION PLANNING PROCESSES?

A. Yes. Outside of Georgia and the ITS, Southern Company participates in the Southeast Region Transmission Planning (SERTP) process. SERTP provides a forum for open and transparent regional transmission planning among many of the largest transmission providers across the southeast.

Q. HOW DOES THE SERTP PROCESS WORK?

A. SERTP produces a Regional Transmission plan constructed primarily from the local transmission plans developed by individual members. SERTP aggregates those local transmission plans into a preliminary expansion plan and conducts a "Bottom-Up Reliability Study Process" to identify any regional transmission constraints. Beyond reliability-based projects and studies included in member's local plans, stakeholders may submit for economic and public-policy studies of potential regional transmission projects. SERTP's Regional Planning Analysis then evaluates new potential regional transmission projects for their capability to more efficiently and cost effectively resolve transmission needs than the lines they would replace in a local plan.

Q. DID SERTP IDENTIFY ANY REGIONAL TRANSMISSION THAT WOULD IMPROVE UPON ITS MEMBERS' MOST RECENT LOCAL TRANSMISION PLANS?

A. No. In fact, since its founding in 2014, SERTP has never identified a regional transmission project that is more efficient or cost-effective to address transmission needs than those proposed in local transmission plans. Over this same history, SERTP has not carried out any public policy studies.[38] SERTP's record suggests that its work prioritizes the local

[38] Regional Transmission Planning Update: Reliable, Affordable Energy Needs More Work (March 2025), available at: https://www.cleanenergy.org/blog/regional-transmission-planning-update-reliable-affordable-energy-needs-more-work/

transmission plans submitted by its transmission provider members to the detriment of regional transmission development and stakeholder participation.

Q. WOULD GREATER INVESTMENT IN REGIONAL TRANSMISSION SYSTEMS BY SOUTHERN COMPANY HELP TO IMPROVE RELIABLITY AND REDUCE COSTS IN THE FACE OF UNPRECEDENTED LOAD GROWTH?

A. Yes. Increased investment in regional transmission can improve reliability and support future load growth, provided it is properly planned in accordance with the transmission best practices recommended herein. A recent study on SERTP conducted by the Brattle Group found that "Southeast utilities need to invest in the regional transmission systems to improve reliability and reduce system costs."[39] However, the Brattle SERTP Report also found that the SERTP Regional Transmission Planning Process is insufficient to meet future system needs and recommended several enhancements to improve the process.

Q. WHAT WERE THE BRATTLE SERTP REPORT'S RECOMMENDATIONS TO ENHANCE THE SERTP REGIONAL TRANSMISSION PROCESS?

A. The Brattle SERTP Report recommended the following enhancements to the SERTP Regional transmission process:

- **Proactively and holistically plan for future generation and load** by incorporating realistic projections of all needs: anticipated generation and

[39] J. Michael Hagerty, Peter Heller, and Even Bennett, *Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy*, Brattle, April 2025, available at Brattle Report: Long-term regional transmission planning (LRTP) offers billions in savings, greater grid reliability to support growing Southeast economy ("Brattle SERTP Report").

load levels over the life 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 needs and benefits.
- **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that accounts for all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging weather 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.[40]

Q. DO YOU AGREE WITH THE RECOMMENDATIONS IN THE BRATTLE SERTP REPORT?

A. Yes. These recommendations from the Brattle SERTP Report are consistent with my recommendation that Georgia Power develop and adopt a long-term, multi-value study

[40] Brattle SERTP Report Executive Summary at 9-10.

approach to joint transmission planning with Southern Company operating companies that meaningfully engages stakeholders.

5 Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission:

1. Direct Georgia Power to update its 2026 utility-scale renewables RFP to require 2 GW of capacity with commercial operation dates of 2032 or sooner.
    a. The average builds of all modeled scenarios result in greater than 3 GW of solar capacity in Georgia Power by 2032.
    b. Insofar as these modeled scenarios reflect the Company's view of all possible futures, the Commission should be able to direct the Company to adopt Recommendation 1 without regret.
2. Direct Georgia Power to add a 2 GW storage RFP in 2026 for projects with commercial operation dates of 2032 or sooner.
    a. The average builds of all modeled scenarios result in greater than 3 GW of 4-hr battery storage capacity in Georgia Power by 2032.
    b. Insofar as these modeled scenarios reflect the Company's view of all possible futures, the Commission should be able to direct the Company to adopt Recommendation 2 without regret.
3. Direct Georgia Power to demonstrate how its long-term capacity expansion modeling informs the timing, magnitude and composition of its resource procurement efforts.

a. The Company should present annual build plans resulting from their modeling, compare their relative performance, and discuss how modeled results are considered in resource procurement efforts.

4. Direct Georgia Power to develop and adopt a long-term, multi-value study approach to joint transmission planning with Southern Company operating companies that meaningfully engages stakeholders. This process should include:
   a. The development of a multi-value benefits criterion that evaluates projects' capacity and dispatch cost savings in addition to existing reliability considerations.
   b. Scenario based modeling captures extreme weather risks and potential benefits.
   c. Collaborative planning with other Southern Company operating companies.
   d. A structure through which stakeholders can meaningfully participate in the planning process such as a transmission advisory group.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	**)**	**Docket No. 56002**
2025 Integrated Resource Plan	**)**	

DIRECT EXHIBITS OF ALEJANDRO PALOMINO

ON BEHALF OF

SOUTHERN RENEWABLE ENERGY ASSOCIATION

May 2, 2025

List of Exhibits

Exhibit Number	Description
AP-1	Alejandro Palomino Curriculum Vitae
AP-2	Telos Energy, Winter Storm Elliot: An Independent Review of Southern Company's Performance During the Historic Events of December 22 – 25, 2022 (2024)
AP-3	J. Michael Hagerty, Peter Heller & Evan Bennett, Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy, Brattle, (2025)

SREA EXHIBIT AP-1:

Alejandro Palomino Curriculum Vitae (CV)

Alejandro Palomino, PhD, Senior Consultant

Energy Strategies | 111 E Broadway STE 1200, Salt Lake City, UT 84111 | apalomino@energystrat.com

PROFESSIONAL EXPERIENCE

Energy Strategies, Salt Lake City, UT, *Senior Consultant*, Jan 2024 – Present; *Consultant*, Aug 2024 – Jan 2024

- Conducted long-term capacity expansion modeling (Aurora) to provide technical support in utility-integrated resource planning intervention across 3 states and 5 utilities
- Developed 8760 price-taker optimal battery dispatch model (Pyomo)
- Built PostgreSQL geospatial database to support distribution system infrastructure with automated updates from utility APIs
- Lead open-source, probabilistic study to evaluate the influence of regional coordination (WRAP) on utility resource adequacy
- Presented findings from "Assessing Resource Adequacy in Montana" to the Montana Energy and Telecommunications Interim Committee
- **Skills**: Aurora · PLEXOS · PostgreSQL · Pyomo · Google Maps API

Duke Energy Commercial Renewables, Charlotte, NC, *SCADA Engineer*, Feb 2016 – Apr 2017

- Managed 7 utility scale (> 5 MW) solar SCADA retrofit projects with a budget of greater than $70,000 each.
- Authored first SCADA controls user manuals in support of operational training needs.
- Supported the operation of 32 solar sites and 12 wind sites by troubleshooting SCADA and networking issues
- Authored standard 3rd Party Vendor Interface Specification to ensure consistent, reliable integration of legacy equipment into the Duke control center
- Saved approximately $13k by performing in house work to synchronize field controllogix PLCs with central SCADA Logix5000 server
- Troubleshot PI interface issues between active sites and Duke control center and documented strategies to improve operations' response to future issues

Siemens Energy, Orlando, FL, *Process and Controls Engineer*, Jul 2013 – Feb 2016; Electrical Engineer, Jan 2013 – Jul 2013; Manufacturing Process Engineer, Jun 2012 – Dec 2012

- Lead I&C design engineer for 800MW combined cycle power plant
- Reviewed P&IDs in building 4000 I/O point database
- Designed cabinet hardware and managed $1.5M budget in purchasing
- Drafted custom motor control circuit diagrams to customer requirements
- Drafted single line diagram for a 3x0 cogeneration gas fired power plant for Royal Dutch Shell

- Participated in electrical design and led early stage electrical proposal for Royal Dutch Shell power control centers and motor control centers
- Authored HW/SW specification for IEC61850 infrastructure upgrade at an existing power plant
- Initialized 20 7SJ Siprotec relays for IEC61850 over TCP/IP motor control center for 2x1 power
- Remote opened and closed a MV circuit breaker using an IEC61850 client simulator (Triangle MicroWorks) via a fiber optic network
- Managed coil shape validation process including a team of 4 operators
- Developed Polyworks computer macros to increase validation efficiency and ease of use for users
- Designed novel clamp set up for pressing process

EDUCATION

The University of Utah, Salt Lake City, UT
Ph.D. in Electrical Engineering, 2022
Dissertation: *Cyber-Secure Utilization of Electric Vehicle Charging Flexibility in Distribution Networks*
Masters of Science in Electrical Engineering, 2020
Thesis: *Probabilistic Analysis of Electric Vehicle Loading on Distribution Infrastructure*

The University of Florida, Gainesville, FL
Bachelors of Science in Mechanical Engineering, 2012
Thesis: *Temperature Monitoring System for High Voltage/High Current Electrical Equipment*

PUBLICATIONS

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- Bagherinezhad, Avishan, **Alejandro D. Palomino**, Bosong Li, and Masood Parvania. "*Spatio-temporal electric bus charging optimization with transit network constraints*." *IEEE Transactions on Industry Applications* 56.5 (2020): 5741-5749.
- **Palomino, Alejandro**, and Masood Parvania. "*Advanced charging infrastructure for enabling electrified transportation*." *The Electricity Journal* 32.4 (2019): 21-26.
- **Palomino, Alejandro**, and Masood Parvania. "*Probabilistic impact analysis of residential electric vehicle charging on distribution transformers*." *2018 North American Power Symposium (NAPS)*. IEEE, 2018.

INTERVENTION WORK

- Iowa Utilities Commission (Docket No. M-0156): Technical Modeling Support of Environmental Law and Policy Center intervention in the 2024 MidAmerican Resource Evaluation Study
- Iowa Utilities Commission (Docket No. RPU-2021-0003): Technical Modeling Support of the Environmental Law and Policy Center intervention in the 2025 Interstate Power & Light Resource Evaluation Study
- Arizona Corporation Commission (Docket No. E-99999A-22-0046): Technical Modeling Support of Western Resource Advocates' Amended Notice of Filing Comments on the 2021, 2022, and 2023 Integrated Resource Plans of Arizona Public Service Company
- Arizona Corporation Commission (Docket No. E-99999A-22-0046): Western Resource Advocates' Notice of Filing Comments on the 2021, 2022, and 2023 Integrated Resource Plans of Tucson Electric Power Company

SREA EXHIBIT AP-2:

Telos Energy, Winter Storm Elliot: An Independent Review of Southern Company's Performance During the Historic Events of December 22 – 25, 2022 (2024)

Winter Storm Elliott

An independent review of Southern Company's performance during the historic events of December 22-25, 2022.



TELOS ENERGY

SOUTHERN RENEWABLE ENERGY ASSOCIATION

Prepared by Telos Energy for the Southern Renewable Energy Association.

Foreword

Winter Storm Elliott was a historic and sobering event, testing the reliability of our power system against extreme weather, high loads, gas supply disruptions, and generator outages.

From December 22 to December 25, 2022, extreme cold gripped much of the country, even extending into the Southeast, pushing grid operators and utilities to their limits. Utilities across the region called for energy emergencies and at times involuntary load shedding occurred.

In the aftermath of the event, FERC and NERC conducted a detailed post-mortem to evaluate root causes of the event. While this report provided valuable insights for each balancing area in the Southeast, it did not include a detailed overview of Southern Company's generator performance, nor did it look at the timeframe most important for Southern Company.

To fill this gap, Telos Energy, on behalf of the Southeast Renewable Energy Association, conducted an independent review of generator performance within Southern Company's footprint during this storm. Our goal was simple: to better understand what worked, what didn't, and what we can learn to improve future grid planning and reliability.

Before diving into the report, we want to recognize the operators who managed the power system during this storm. They no doubt worked tirelessly to maintain service for their customers and their communities. Southern Company managed to avoid rolling blackouts during the extreme weather—while neighbors could not.

Operators made decisions under immense pressure, ensuring customers had heat, preventing property damage and even saving lives.

This report is not about second-guessing those efforts. Instead, it aims to shed light on generator performance and planning processes, helping ensure our future systems can withstand similar events.

What this storm highlighted is that no resource is perfect and all resources - whether natural gas, coal, hydro, wind, or solar - are affected by the weather. Robust and fair accreditation of all resources is essential not just to make informed investment decisions, but to ensure reliability.

This starts with accrediting natural gas and coal resources using effective load carrying capability similar to what is being done for solar and battery storage. It also extends to interregional transmission, which can also be treated as a capacity resource. Together, proper accreditation can enable a diversified portfolio that strengthens the grid.

Transparency is another cornerstone of effective planning. Much of our analysis relied on data from Georgia Power Company's (GPC) regulatory filings, but gaps remained, requiring us to piece together a fuller picture using publicly available sources like EPA and EIA datasets.

At times we had to use generation during EEA events as a proxy for availability and outages. No doubt there are small errors or omissions in this analysis, and we look forward to additional data to help correct these. Transparency matters—not just for analysts like us, but for regulators, planners, and stakeholders who need accurate information to make informed decisions.

We hope this report serves as a constructive step toward greater understanding of past events and enables more robust planning. Together, let's continue building a grid that's ready to meet the reliability challenges ahead.

Introduction

Winter Storm Elliott created severe stress on the electric grid from December 21 - 26, 2022. The storm brought extreme cold, high winds, and snow, leading to a dramatic surge in electricity demand coupled with widespread outages caused by freezing equipment and disrupted fuel supplies.

Many utilities, including those in regions managed by the Tennessee Valley Authority (TVA), PJM (Pennsylvania-New Jersey-Maryland Interconnection), Duke Energy, and Southern Company, faced challenging conditions and implemented emergency procedures to maintain grid stability. The North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC) subsequently released reports[1] detailing the storm's impact on utilities and highlighted region-wide deficiencies in both electric-gas coordination and preparedness for extreme weather. These reports underscored the urgency of enhancing reliability frameworks to address correlated failures across energy and fuel networks.

Post-storm scrutiny focused on the severe impacts in TVA, PJM, and the Carolinas where there was involuntary load shedding. However, Southern Company and its subsidiaries—Georgia Power, Alabama Power, Mississippi Power, and Southern Power—also faced substantial operational challenges.

On December 24, 2022, Southern Company issued an Energy Emergency Alert Level 2 (EEA 2), signaling the need to manage load through voluntary reductions. Unlike TVA and other utilities that implemented controlled outages, Southern Company managed to avoid EEA 3 measures which would have triggered involuntary load shedding, or "rolling blackouts."

During this time, the thermal generating fleet across the eastern interconnection experienced widespread outages, fuel supply disruptions, and unavailability. Figure 1 below shows a timeline of hourly electricity demand from the Southern Pool with callouts for key periods identified in this analysis. Additionally, yellow bars indicate approximate times when neighboring regions were under EEA 1 to EEA 2 and orange bars represent regions where EEA 1 to EEA 3 conditions occurred in relation to Southern. Periods of EEA for non-Southern regions represent approximate times any EEA was in effect.

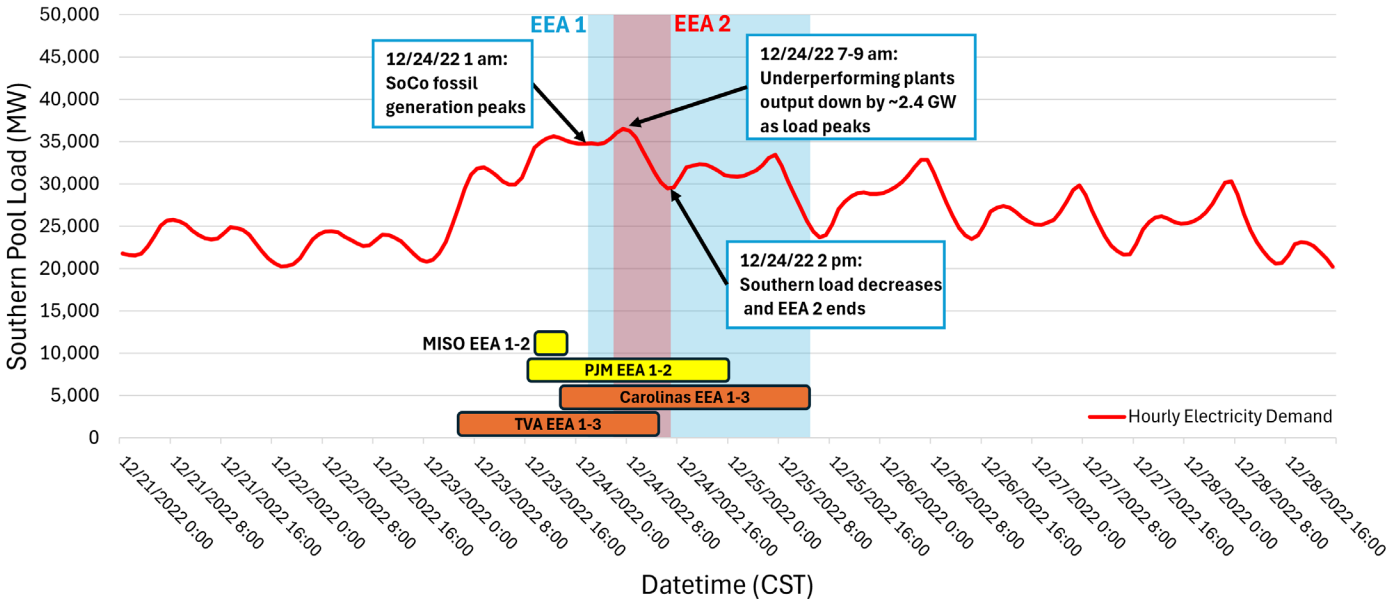


Figure 1. Summary timeline for Southern Company generator performance during Winter Storm Elliott

1 *FERC, NERC, & Regional Entity Staff. (2023, October). Inquiry into bulk-power system operations during December 2022 Winter Storm Elliott. Retrieved from https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott*

The EEA declaration underscores the significant strain on its system, prompting an examination of the company's resource preparedness, load forecasting accuracy under extreme conditions, and planning processes to mitigate risks to system reliability and control costs for ratepayers. It also highlights the importance of including these types of weather events – and the corresponding generator performance – in long-term planning.

This report evaluates Southern Company's performance in key areas during Winter Storm Elliott, including generator performance, load forecasting accuracy, and both bilateral and SEEM market transactions. Key findings explore how well Southern Company anticipated and mitigated cold weather risks, the extent of generator derates or outages during the event, and the performance of renewable resources under extreme conditions.

Transparency remains a key challenge: although power purchases increased significantly during Southern Company's EEA 2 event, limited information is available, particularly regarding price formation, leaving ratepayers to bear unclear emergency costs.

The company's forecasting and planning for winter peak loads appear insufficient for managing high-impact, low-frequency events without resorting to extreme measures, and further assessment is needed to ensure Southern Company is accounting for winter outage risks across its generation fleet.

As a vertically integrated utility operating in a non-organized market, Southern Company lacks the standardized post-event reporting and market transparency seen in regulated regions like PJM and MISO. This limited transparency restricts a full evaluation of Southern Company's operational decisions and financial impact on ratepayers. Consequently, stakeholders lack critical insights into the company's efficiency, resource planning efficacy, and the true costs of emergency power.

This report addresses these gaps using limited data available from Georgia Power dockets, EPA data on large fossil-fuel plant operations, and grid operation data from the Energy Information Administration (EIA), seeking to answer critical questions on Southern Company's performance during Winter Storm Elliott.

This report seeks to address four primary questions:

- **Winter Load Forecasting:** How well does Southern Company predict winter peak load events, and did actual risks during the storm align with utility expectations?
- **Generator Performance:** How did all generation resources perform during severe conditions, and how effectively does Southern Company account for cold weather outage risks in its planning?
- **Emergency Power Purchases and Costs:** From where did emergency power originate, and at what cost? How did these costs compare to those in nearby regional markets?
- **Southeast Energy Exchange Market (SEEM) Performance:** How was the Southeast Energy Exchange Market (SEEM) leveraged during Winter Storm Elliott, and how has it been used in subsequent winter peak load events in 2023 and 2024?

"Transparency remains a key challenge: although power purchases increased significantly during Southern Company's EEA 2 event, limited information is available, particularly regarding price formation, leaving ratepayers to bear unclear emergency costs."

This report aims to inform Southern Company stakeholders and regulatory authorities on the overall performance of the generation fleet, how well winter risk is characterized, and opportunities for increased transparency during and after emergency events, and recommendations on how to better incorporate these challenges in long-term planning.

Winter Load Forecasting

The Southern Company region operates as a dual-peaking system, with high loads and tight reserve margins both in summer, due to air conditioning demands, and in winter, due to electric heating needs.

Every year, the Southern Balancing Authority (SBA), comprising Southern Company subsidiaries like Georgia Power, Alabama Power, and Mississippi Power, develops both a base winter peak load (50/50 load forecast) and an extreme peak load (90/10 load forecast) to prepare for severe weather scenarios. For the 2022-2023 winter season, SBA's extreme winter peak load forecast was 45,462 MW, slightly under the all-time winter peak of 45,887 MW[2].

To meet these forecasted loads, SBA projected resource availability based on its planning criteria, estimating 53,759 MW of resource capacity. After accounting for planned and unplanned outages and demand response, total capacity available was 52,133 MW. Under the 90/10 extreme peak forecast, the SBA projected reserve capacity of 6,671 MW, indicating a 15% reserve margin.

Given these assumptions, SBA anticipated sufficient resources to cover demand even during challenging weather like Winter Storm Elliott. However, on December 24, despite actual peak load remaining slightly below the 90/10 forecast at 45,153 MW, the SBA entered both EEA 1 and EEA 2 conditions, signaling that actual resource availability was below expectations during this high-demand period.

Table 1 shows the winter reliability expectations going into Winter Storm Elliott from the NERC/FERC inquiry.

2022-2023 Winter Reliability Load and Resource Summary	Southern
50/50 Winter Forecast (MW)	41,300
90/10 Winter Forecast (MW)	45,462
Winter Storm Elliot Peak (MW)	45,153
Expected Available Resources (MW)[3]	52,133
Expected Reserves to 50/50	26.2%
Expected Reserves to 90/10	14.7%
Expected Reserves to Actual Peak	15.5%

Table 1. Southern Winter Reliability Summary from NERC and FERC Inquiry into Winter Storm Elliott.

Evaluating Operational Forecast Accuracy and Error Margins

Reviewing the 2022 resource adequacy assessments for the Southern Pool (Georgia Power, Mississippi Power, and Alabama Power) reveals significant forecasting challenges for December peak loads. The historical data shown in Table 2 *(page 5, top)* shows that high forecast error exists even 1-hour ahead of peak load in December. For Winter Storm Elliott, the average error leading up to peak load would be 271 – 455 MW, depending on how far ahead the forecast is made. Assuming that the standard deviation is for a normal distribution, there was a 16% probability that December peak load could have been more than 3,600 MW above the forecasted peak load based on historical forecast error.

This high variability in forecast winter peak load means grid operators face high levels of uncertainty during extreme cold weather. Even though going into the event it appeared that adequate reserves were available, and peak load would be within the 90/10 forecast, clearly risks developed that prompted emergency procedures.

More insight into the specific decision-making steps from normal operations to EEA 1, 2, and potentially EEA 3 would help contextualize the risks of Winter Storm Elliott. Post-event analysis reports are commonplace in regions with markets, like PJM, MISO, and SPP, since market transparency builds trust and creates accountability for remedial actions.

2 Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC), FERC, NERC Release Final Report on Lessons from Winter Storm Elliott (2023), available at https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.

3 Expected available resources includes 53,759 MW of capacity, 2,510 MW of demand response, and -4,136 MW of expected planned and forced outages.

Historical Peak Load Forecast Error	Peak Load	4-hour mean error	1-hour mean error	4-hour std dev	1-hour std dev
December Error		1.0%	0.6%	10.4%	8.0%
Winter Storm Elliott Risk	45,153 MW	455 MW	271 MW	4,696 MW	3,612 MW

Table 2. 2022 Georgia Power Reserve Margin Study Historical Dispatchers' December Peak Load Forecast Error

Greater transparency in Southern's decision-making framework could clarify whether improvements are needed in forecasting accuracy, resource adequacy modeling, or operational protocols.

Suggestions to Improve Confidence in Winter Planning

Though Winter Storm Elliott brought conditions close to the 90/10 forecast, the region experienced emergency conditions not anticipated by existing plans. Despite projected reserves, the system escalated to EEA 2 conditions, where voluntary load reductions were employed.

This raises questions about whether Southern is making appropriate assumptions on generator availability during extreme, but anticipated, winter weather.

As winter reliability grows increasingly critical, Southern Company's strategies and readiness for low-frequency, high-impact events like Winter Storm Elliott require further scrutiny, particularly given the challenges of electric-gas coordination and growing electricity demand from data centers and electric vehicles.

The following actions are recommended to improve winter peak planning and transparency for stakeholders:

- Improvements to mitigate volatility in winter peak load are needed. These could include more advanced demand side management strategies, improved home efficiency programs, or virtual power plants to mitigate winter peak load risk while mitigating transmission system constraints.
- Evaluate load diversity and peak load risks for neighbors outside of SERC to enable more robust interregional support during high impact low probability events.

Generator Performance

The following analysis reviews how generators and different fuel types across Southern Company's footprint performed during Winter Storm Elliott.

Given the scale and severity of the event, units were expected to maintain or increase output to meet peak demand, especially as the region moved into EEA 1 and EEA 2. However, after reviewing generation data, significant drops in capacity or availability during this period are assumed to indicate operational challenges. The period used to evaluate generator performance is referred to as the "emergency window" which extends from December 24th at 7 am – 9 am. This three-hour window surrounding the peak load hour is used to represent the hours of greatest risk across the region.

Unfortunately, actual operational data was only provided by Georgia Power. Data transparency limitations make it challenging to assess performance throughout the broader balancing authority. This results in substantial gaps for Mississippi Power, Alabama Power, and Southern Power. This lack of detail underscores the need for Southern Company to provide comprehensive post-event analyses for their entire footprint. This practice aligns with other regions and supports transparent planning for system reliability and ensures accountability.

Overall Southern Company Fossil Fleet Performance by Fuel Type

The performance of Southern Company's fossil-fuel fleet, broken down by fuel type, is illustrated in Figure 2 *(below).* Total generation is from EPA's Continuous Emissions Monitoring System (CEMS) data, discounted by 2-7% based on technology type to approximate auxiliary loads. The gap in the data represents the remaining amount of demand served by nuclear, hydro, solar, and external power purchases.

Fossil-fuel generation in Southern Company's territory declined throughout the EEA 2 period when risks were highest, despite calls for voluntary load reductions. Fossil-fuel generation declined 2.4% in the hours before, 3.3% during, and 6% in the hours following peak load. Load shown in the figure represents the total reported generation from Georgia Power for all Southern Company entities.

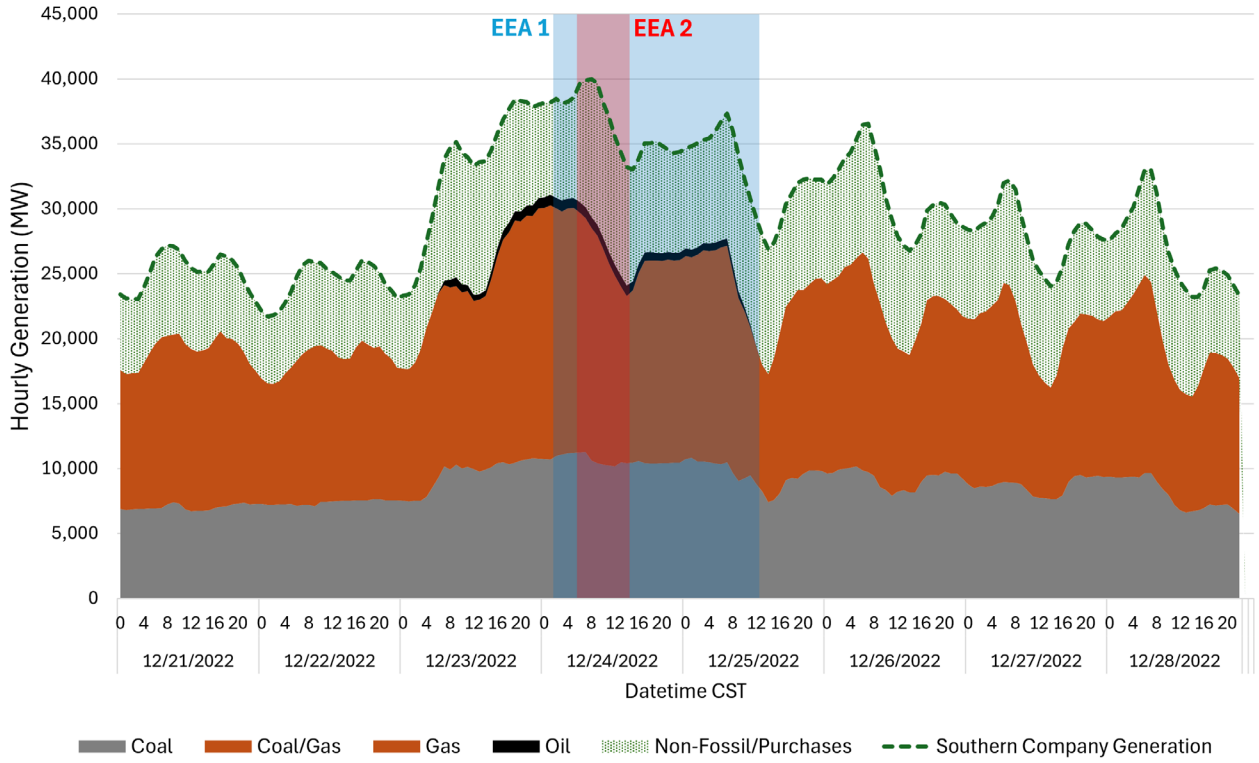


Figure 2. Southern Company Fossil Generation by Fuel Type during Winter Storm Elliott.

The data indicates that fossil generation peaked approximately 5 hours before peak load with numerous outages occurring when the capacity was needed most.

The fleetwide capacity factor for each fossil fuel type during EEA 2 is shown in Figure 3 *(below)*. Notably, coal and natural gas generation decreased by 7.5% and 8.1% relative to their maximum leading up to the emergency window.

While no load shedding occurred as the fleets experienced outages during EEA 1 and EEA 2 periods, the effects of cold weather on outage rates warrants further evaluation due to the volatility in winter demand described in the Winter Load Forecasting section.

Based on the emergency window of 7 am – 9 am on December 24, there were 22 plants (including aggregated one) that had either known outages reported by GPC, or had substantial deviations in the EPA data, or simply did not generate at all during the event.

These plants' winter ratings total 15,816 MW; however, average generation across these units was 8,084 MW, meaning that during the most extreme hours of the storm these units were only operating at 51% capacity factor across the fleet 51%.

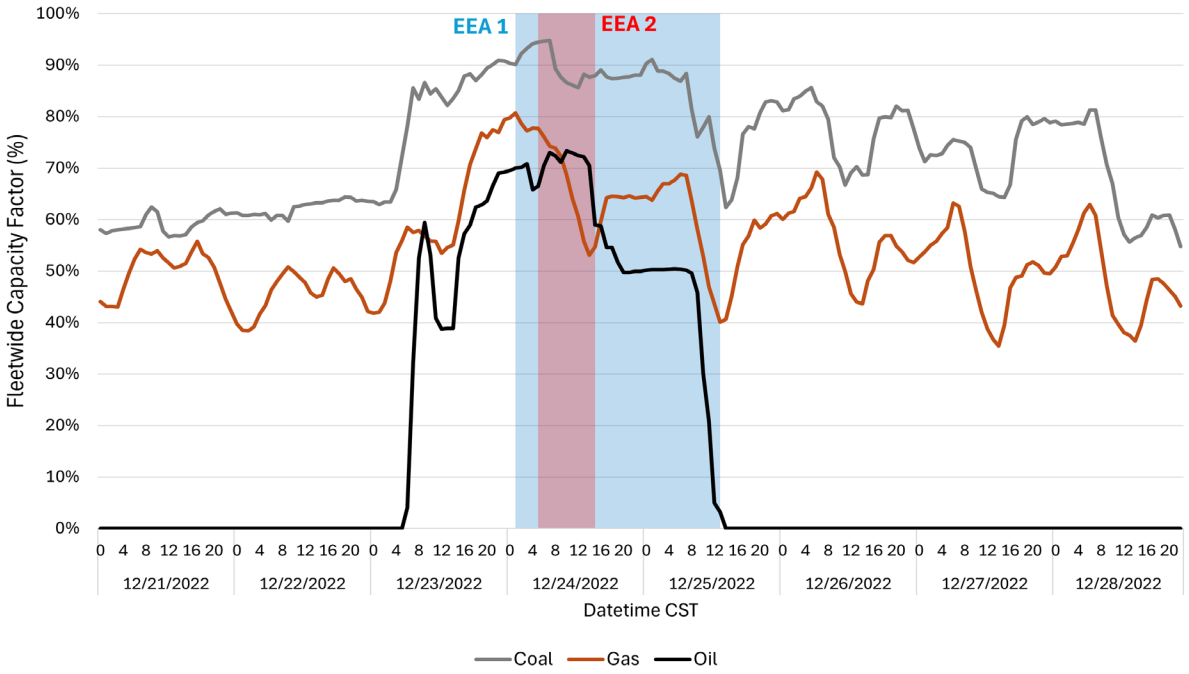


Figure 3. Southern Company Fossil Fleet Capacity Factors during Winter Storm Elliott.

Not all the unavailability exhibited by these plants can be attributed to forced outages without additional information. But the fact remains that these plants either had generators on some type of outage or were experiencing derates due to fuel supply availability during the emergency window. Figure 4 *(page 8, top)* shows the plants identified as underperformers and their average generation during the emergency window.

Generators that were GPC power purchase agreements were aggregated if they were less than 100 MW. Undispatched capacity represents the delta between the generation during the emergency window and the plants winter ratings.

In some cases, units were completely unavailable, in others output had been decreasing since the EEA 1 period was declared, or sharp drops in generation were observed in at least one of the emergency window hours.

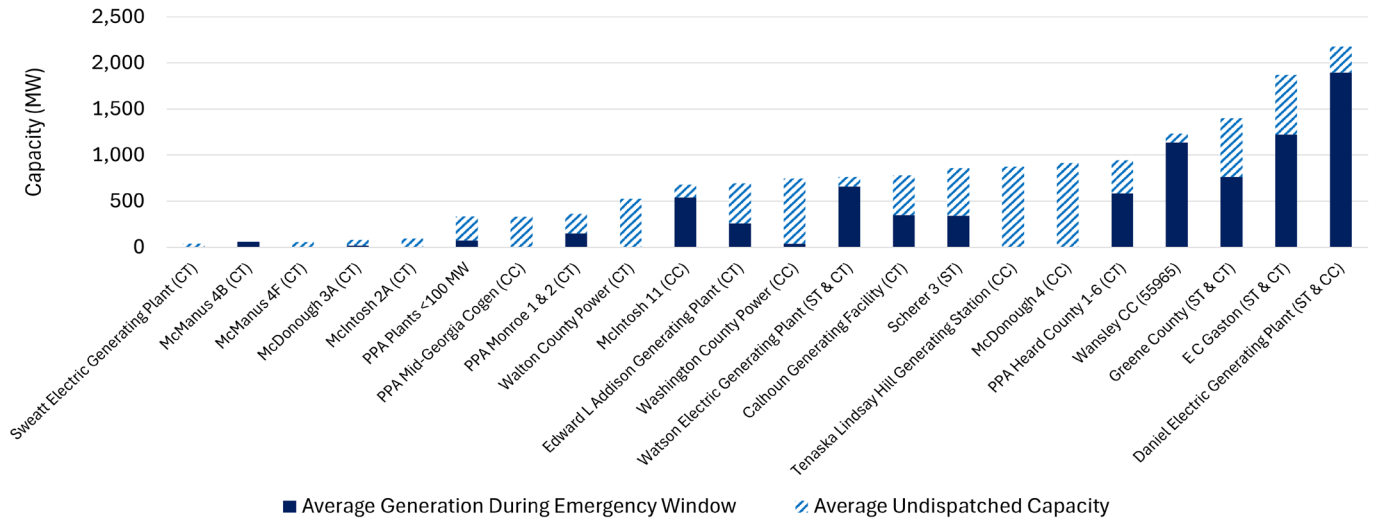


Figure 4. Southern Company known and potential unavailable capacity due to outages on 12/24/2022 hours 7am - 9am CST.

Known Georgia Power Plant Outages

This section provides a review of available hourly generation data for plants that experienced known outages as reported by Georgia Power. More information on the entire company's performance is needed to accurately determine where and when cold weather affects power plant outages although further sections provide estimates of unavailable capacity by Southern Company subsidiary and PPA resources.

Georgia Power Company owned plants where known outages occurred on December 24, 2022, from 1 am – 1 pm are:

- McDonough Unit 4 – 808 MW Combined Cycle
- McIntosh Unit 11 – 294 MW Combined Cycle
- McDonough CT 3B – 40 MW Combustion Turbine
- McIntosh CT 2 – 94 MW Combustion Turbine
- McManus CT 4B – 55 MW Combustion Turbine
- McManus CT 4F – 55 MW Combustion Turbine
- Scherer 3 – 644 MW Coal Steam Turbine

Including a planned derate of 71 MW at the Hatch nuclear plant, a total of 2,061 MW of GPC owned resources out of 14,092 MW of capacity resources (15%) were on outage during Southern Company's highest risk period during the storm.

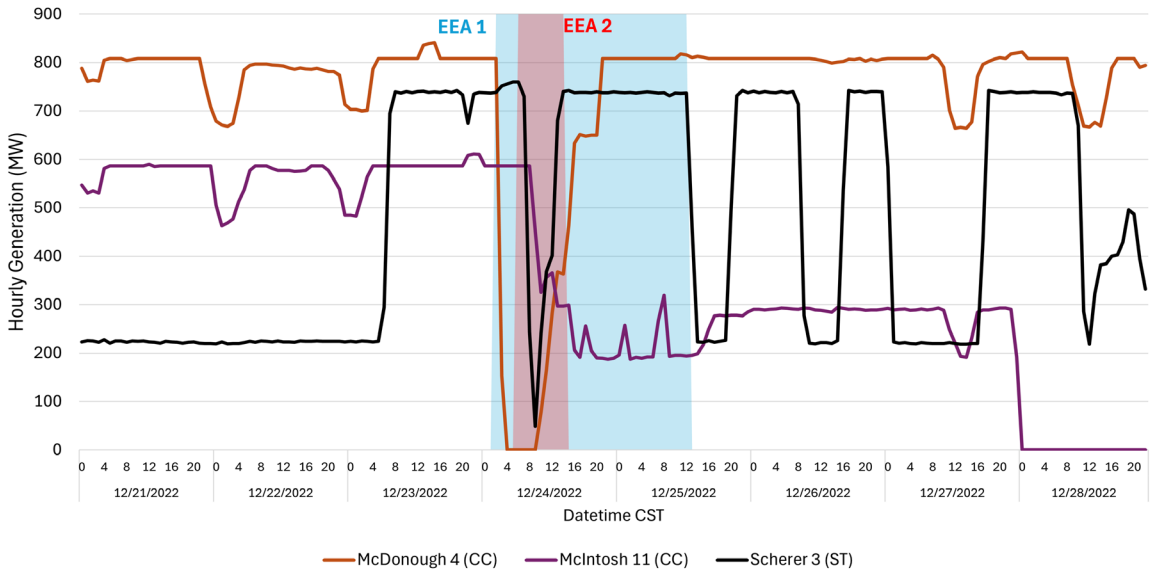


Figure 5. Hourly Generation for Large GPC Units with Outages During Winter Storm Elliott.

Figure 5 *(page 8)* shows the operations for McDonough Unit 4, McIntosh 11 and Scherer 3 based on GPC provided hourly generation data.

The timing of outages for each of the three units shown above varies, but the most significant impact is what the total amount of generation was on outage during the peak load hour. Based on Energy Information Administration winter ratings for these three units had 1,622 MW of reduced output during peak load. The worst-case level of reduced output for these three plants was 1,952 MW, one hour after peak load.

Figure 6 *(below)* shows the smaller unit outages during this period. Notably, McManus appears to have returned to service in time for the EEA 2 event. Both McDonough 3A, and McIntosh 2A, and McManus 4F were either unavailable during the EEA 2 event or unable to operate at their maximum rating.

The total amount of these plants operating below their rating during the peak load was 212.6 MW, one hour after peak load.

It is not unreasonable for power plant outages to occur during extreme weather conditions. Additional information provided by GPC indicated that the 2,061 MW of outages GPC experienced resulted in 15% of their total capacity resources on outage during the storm.

In addition to the GPC owned resources on outage, a total of 1,031 MW of GPC Capacity PPA resources were on outage during the storm. These units were not identified but represented 25% of GPCs capacity PPA resources. In total, 14.5% of the GPC owned and GPC PPA fleet experienced a forced outage during Winter Storm Elliott[4].

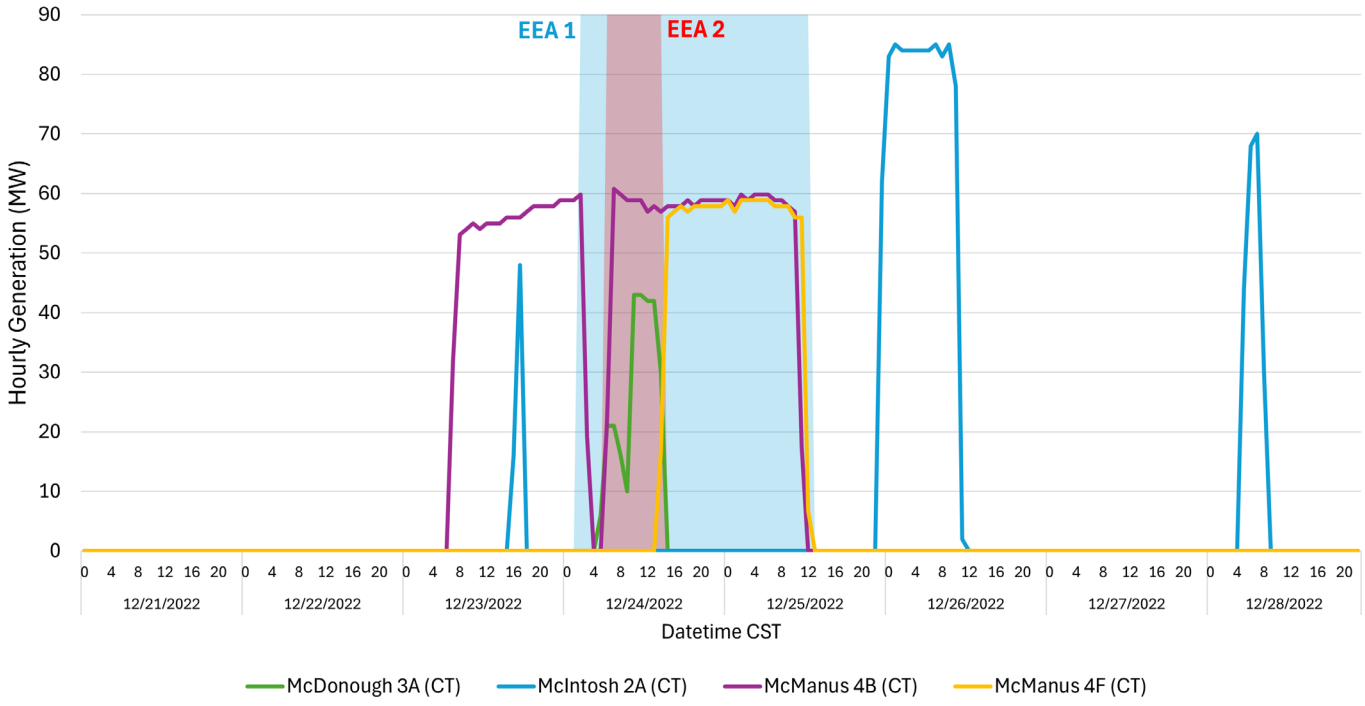


Figure 6. Hourly Generation for Small GPC Units with Outages During Winter Storm Elliott.

Performance of Non-Georgia Power Generators

The previous section only reviewed Georgia Power generators because the unit-specific data was made available in regulatory filings. To augment this data, a review of other Southern Company resources was conducted using publicly available data from the EPA CEMS database. All owned or PPA resources from Alabama Power, Mississippi Power, and Southern Power that were equipped with emissions monitoring systems were reviewed.

While only gross generation data is available, power plants that showed substantially low output or significant deviations during the emergency window (7 am to 9 am) were deemed potential outages.

4 Docket No. 55378, Georgia Power Company's 2023 Integrated Resource Plan Update – Hearing Request Set Number 1 (HR-1-1)

This assumes that the resources would have been utilized further, if available, to avoid EEA 2 and xpensive market purchases.

Performance of Alabama Power Generators

Review of Alabama Power fossil fueled generation showed three dual fuel gas/oil power plants with declining output or substantially reduced output. Figure 7 *(below)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data. These plants stand out because due to overall lower generation than might be expected during the event considering emergency purchases were required.

The three plants shown here are:

- 1,400 MW Greene County (owned by Alabama Power and Mississippi Power)
- 1,872 MW E C Gaston plant (owned by Alabama Power and Georgia Power), and
- 80 MW Calhoun Generating Facility.

During the emergency window, Greene County output was 318 MW lower than the maximum during EEA 1. E C Gaston output was 20 MW lower, but overall output was limited to only 65% of its capacity. Calhoun Generating Facility output was 255 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages. In total, these three plants had reduced output of approximately 1,881 MW at their worst hour during the emergency window.

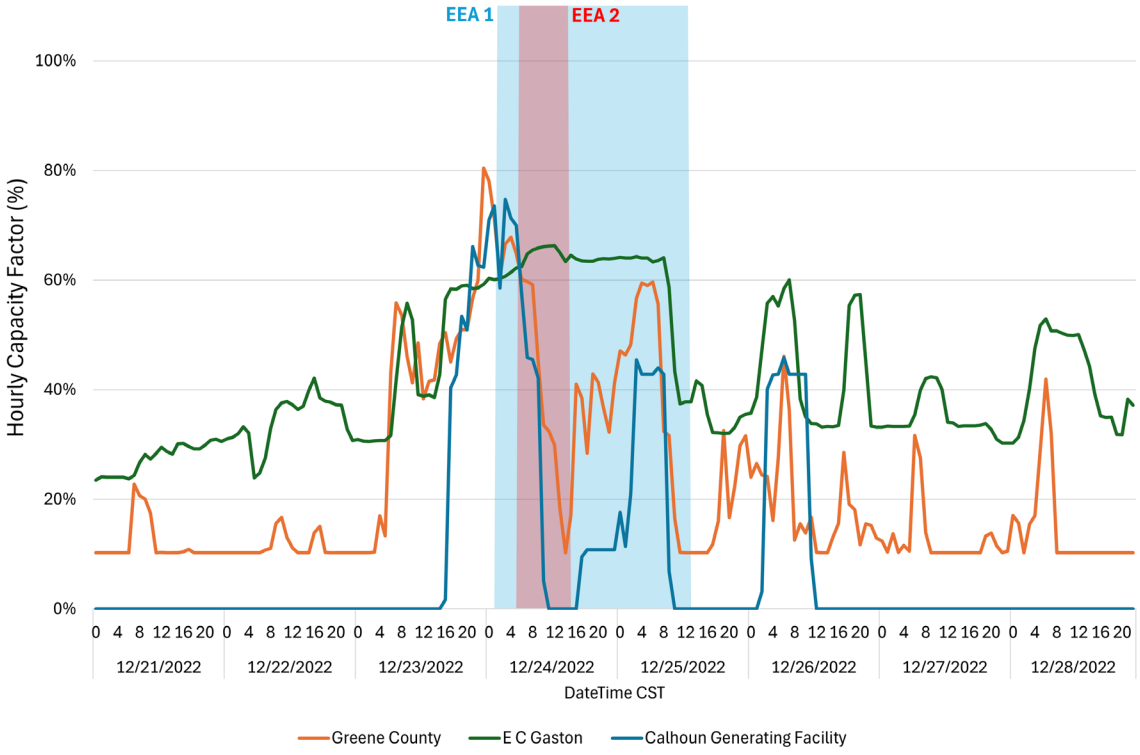


Figure 7. Alabama Power generation identified as having potential outages during Winter Storm Elliott.

In addition to the fossil fueled plants, Unit 1 at the 1,791 MW Joseph M Farley nuclear plant in Houston, AL was offline until the EEA event occurred. This unit represents 895 MW of capacity unavailable to the system due to a planned refueling outage. Typically, refueling outages aren't notable because they are scheduled in the shoulder season where risk is lower.

However, in 2022 the refueling outage for Farley 1 started on 9/18/2022 and didn't end until 12/22/2022 when the unit started slowing increasing output. This represents a 95 day outage for the unit. Typically refueling outages are between 30-45 days indicating the system faced higher risk in the winter due to the extended outage at the unit.

Figure 8 *(below)* shows the daily power reactor status report for Farley 1 from 12/21/2022 – 12/28/2022. Data is interpolated for each day since the reactor reports status at the beginning of each day. The squares on the chart represent the daily power reactor status report percentage of power output.

By the time of the EEA 1 and EEA 2 declaration Farley 1 was estimated to be between 18-30% of its rating, meaning an additional 638.4 - 733.9 MW had yet to ramp up. The extended refueling outage timeline exacerbated risks in December which is a highly volatile winter month.

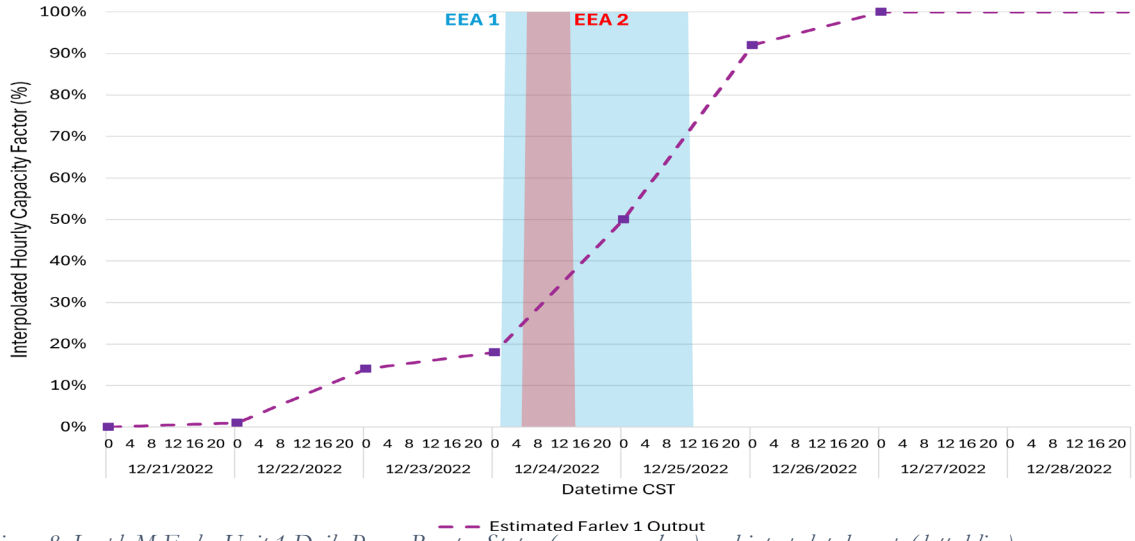


Figure 8. Joseph M Farley Unit 1 Daily Power Reactor Status (square markers) and interpolated ramp (dotted line)

Performance of Mississippi Power Generators

Review of Mississippi Power fossil fueled generation showed three plants where output leading up to the peak load hour was declining or well below its winter rating. Figure 9 *(page 12, top)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data.

These plants stand out because of substantial deviations in generation during the emergency window due to overall lower generation than might be expected during the event considering emergency purchases were required.

The three plants identified as having potential outages or were the:

- 41 MW Sweatt Electric Generating Plant
- 762 MW Watson Electric Generating Plant, and
- 2,180 MW Daniel Electric Generating Plant.

The Sweatt Electric Generating Plant appears to have been offline or unavailable throughout the entire period. This may indicate an extended outage that started before the storm.

This unit was flagged because no operations were found at any point during the EEA 2 period.

During emergency window, the Watson Electric Generating Plant output was 163 MW lower than its maximum during the EEA 1 period that morning. The Daniel Electric Generating Plant output was 436 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages.

In total, these two plants' output during the emergency window was lower by 598 MW. Including Sweatt in the total brings it to 639.5 MW.

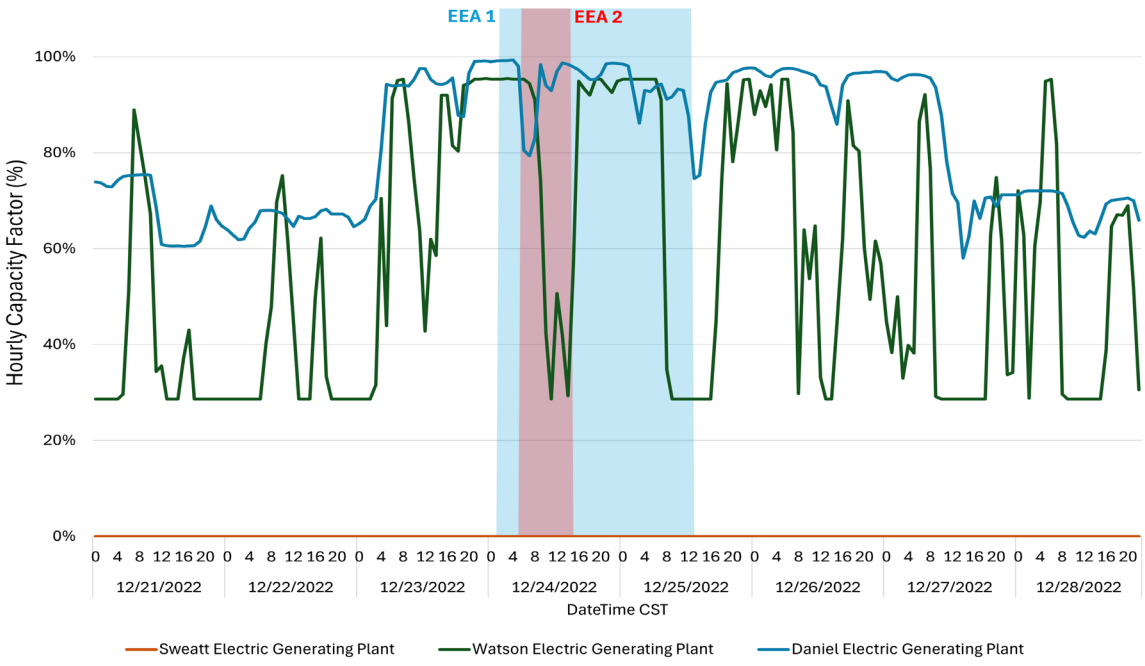


Figure 9. Mississippi Power generation identified as having potential outages during Winter Storm Elliott.

Performance of Southern Power Generators

Review of Southern Power fossil fueled generation showed two plants where output leading up to the peak load hour was declining or well below its winter rating. Figure 10 *(below)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data. These plants stand out because of substantial deviations in generation after EEA 1 and EEA 2 were declared and due to overall lower generation than might be expected during the event considering emergency purchases were required.

The two plants identified as having potential outages or derates during the EEA period were the 693 MW Edward L. Addison Generating Plant and the 1,233 MW Wansley Combined Cycle.

During the emergency window, the Edward L. Addison Generating Plant output was lower by 275 MW relative to the EEA 1 hours prior. The Wansley Combined Cycle output was 209 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages. In total, these two plants' output during the emergency window was lower by 483 MW.

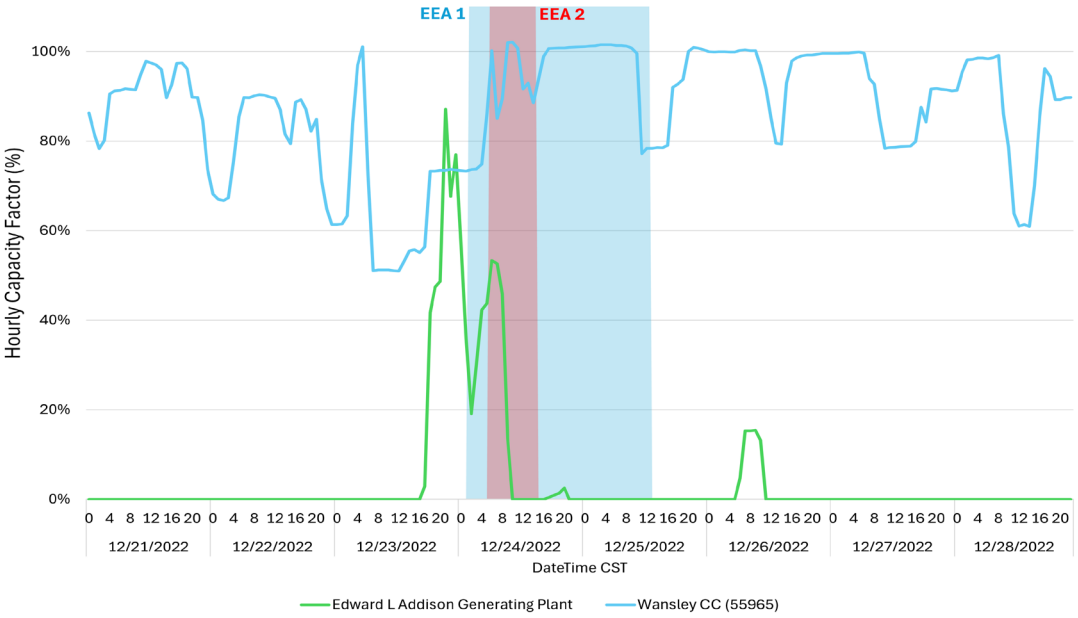


Figure 10. Southern Power generators identified as having potential outages during Winter Storm Elliott.

Performance of PPA Generators

In addition to utility owned assets, Southern Company and its subsidiaries also procure capacity and energy via PPAs.

These types of resources use a variety of fuels, including gas, landfill gas, oil, and biomass. EPA data is not available for non-utility generating units, nor units that are less than 25 MW in size. Due to this limitation, only those PPA units that are known to contract with Southern Company subsidiaries and met the size threshold or those that Georgia Power provided data on were reviewed in this section. Generation by plant for different fuel types is reviewed in the following subsections.

Biomass PPA Generator Performance

Data was only available for biomass generators reported in the Georgia Power IRP and provided in the docket request. Review of these units' output leading up to and during the peak load hour shows a general underperformance relative to the size of the PPA.

Figure 11 *(below)* shows the five plants that had zero output during the peak load hour. The hourly data shown also indicates little to no generation for these plants during the entire EEA 1 and 2 period. The total capacity unavailable during the emergency window was 230 MW out of 302 MW of biomass PPA resources.

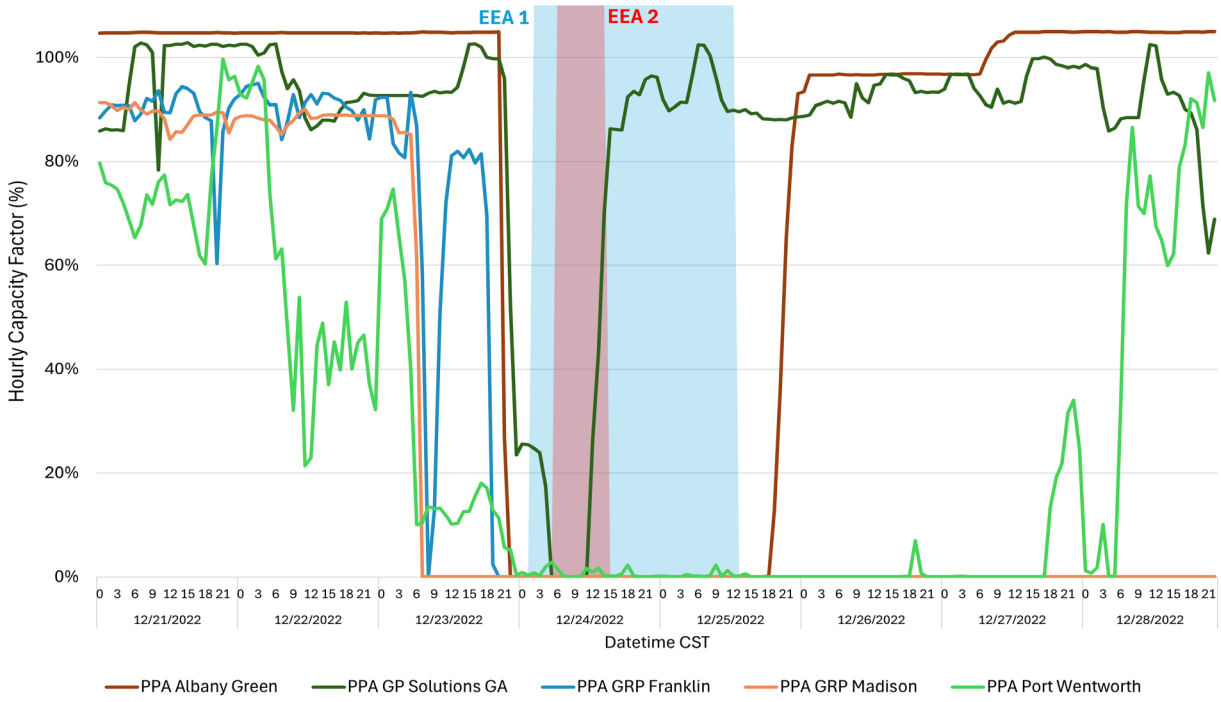


Figure 11. Georgia Power Biomass PPA generators identified as having potential outages during Winter Storm Elliot.

Landfill Gas (LFG) PPA Generator Performance

Data was only available for landfill gas generators reported in the Georgia Power IRP and provided in the docket request. Review of these units' output leading up to and during the peak load hour shows a general underperformance relative to the size of the PPA.

Figure 12 *(page 14, top)* shows that all five plants had zero output during the peak load hour. The hourly data shown also indicates no generation for these plants from 12/23/2022 to until the morning of 12/27/2022. The total capacity unavailable during the peak load hour was 32.3 MW and 100% of the LFG PPA resources.

Gas PPA Generator Performance

Several larger gas generators that are not owned by Southern Company also serve load via PPAs. A review of both the EPA CEMS data and data provided by Georgia Power shows that six plants had potential outages or derates leading up to the peak hour.

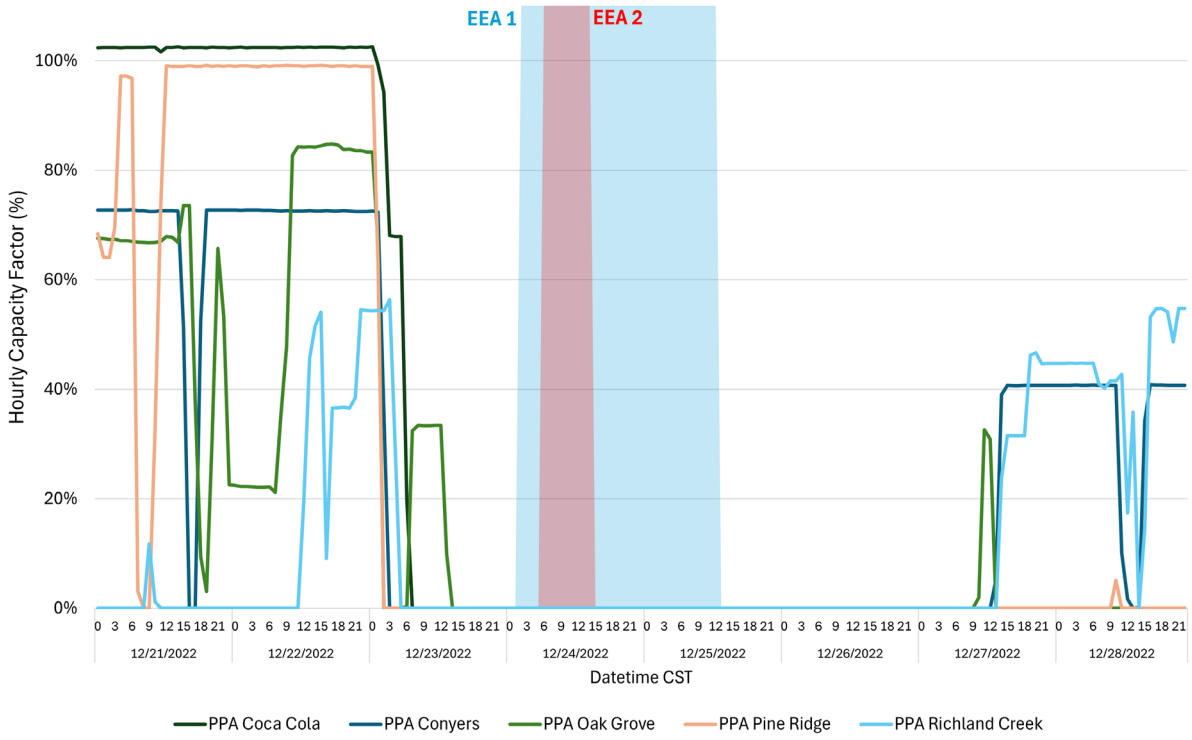


Figure 12 Georgia Power LFG PPA generators identified as having potential outages during Winter Storm Elliott.

Figure 13 (below) shows the hourly generation data for the plants using EPA CEMS data. These three units shown indicate likely low resource availability that is likely not attributable to Winter Storm Elliott except for potentially Washington County Power which sees a reduction in outFigure 13. Additional Southern Company PPA generators identified as put going into the EEA 1 period. Relative to their winter capacity ratings, the lack of generation totals 2,044 MW.

Additional information based on monthly net generation for each of the facilities in 2022 and 2021 indicate that there may have been extended outages at all three plants since monthly net generation was either 0 or substantially reduced in October, November, and December relative to the same months in 2021.

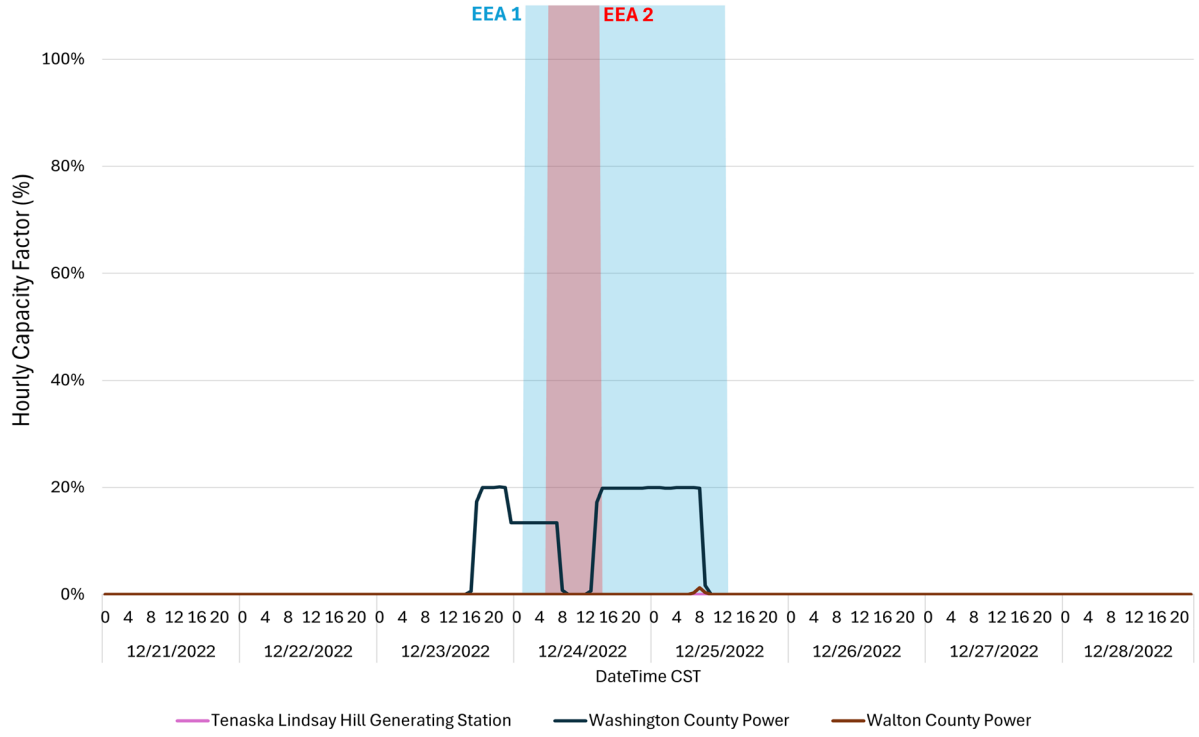


Figure 13. Additional Southern Company PPA generators identified as unavailable during Winter Storm Elliott based on EPA CEMS data.

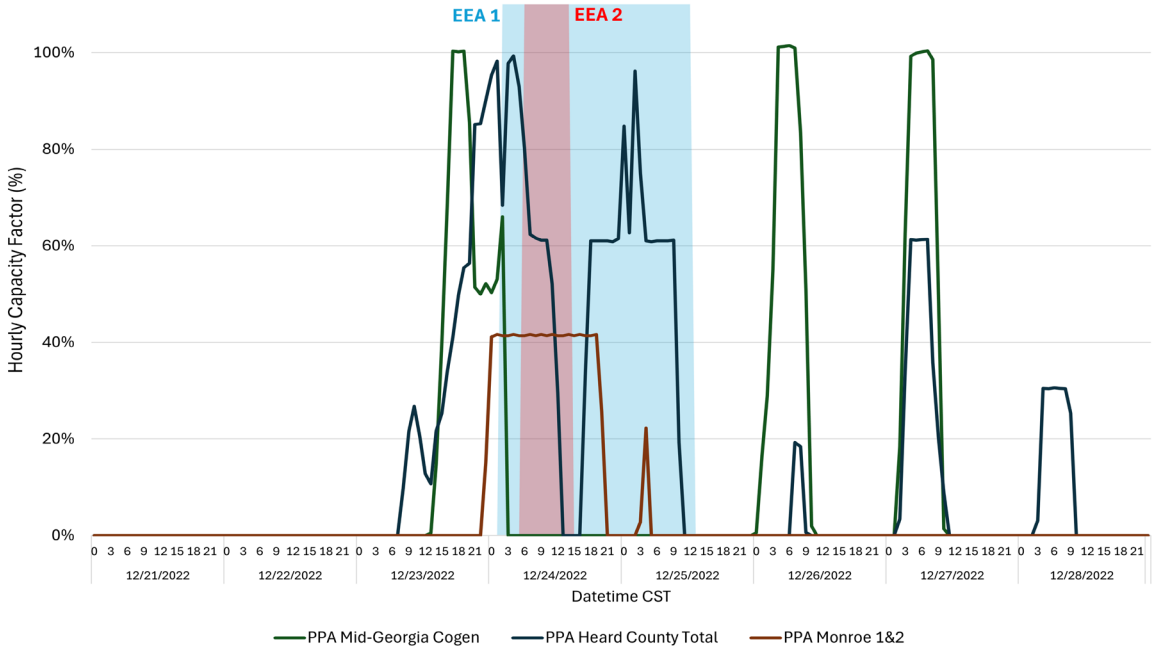


Figure 14. Additional Southern Company PPA generators identified as unavailable during Winter Storm Elliott based on Georgia Power data.

Figure 14 *(above)* shows the hourly generation data for additional PPA plants using Georgia Power provided data. The three plants are the 945 MW Exelon Heard facility (also called Tenaska Georgia Generating Station), the 300 MW Mid-Georgia Cogen, and the 360 MW Monroe plant (also called MPC Generating).

The data shown indicates that all three plants faced decreased generating capability during the emergency window. The Mid-Georgia Cogen plant has a noticeable drop in generation down to 0.

The Heard County plant has a similar trajectory where the plant is at full output prior to the event and eventually drops to 62% output during the peak load hour. Lastly, the Monroe facility was operating only at 41% output due to no generation from Monroe unit 2 during the EEA period. In total, these plants provided 727 MW of output during the emergency window relative to their total 1,635 MW winter ratings.

Evaluating Incremental Cold Weather Outages

In their 2022 IRP, Georgia Power shared the Southern Pool's assumptions on incremental cold weather outages for Southern Company resources. Their recognition that cold weather increases the probability of generators going on outage is a best practice; however, the data provided is highly aggregated, assuming all unit types are affected equally, and only shown at the pool level.

Risks will vary by fuel type and by region in the pool and should be communicated as such.

Additionally, Southern Company assumed in their analysis that actions they took reduced cold weather outage risks in the future relative to the historical period. This is shown by the shift down and to the left of the orange line (assumed improvements) relative to the blue line (historical performance) in Figure 15

Considering Winter Storm Elliott and upcoming IRPs, these assumptions should be re-evaluated to ensure they are valid. The results of applying these assumptions to their modeling process should be documented in more detail to show the magnitude of additional outages that can occur as temperatures drop. Reporting the worst-case fleet availability level rather than just the incremental effect would go a long way in properly communicating what cold weather risks look like for the generation fleet.

Based on the data from the 2022 Georgia Power IRP, the fleetwide incremental cold weather outages are shown in Figure 15 *(page 16, top).* Based on Figure 15 and an average temperature of 7 degrees F during the morning of 12/24/2022 across Southern Company the improved incremental outage rate was 2.77%. The original incremental cold weather outage rate was 5.28%.

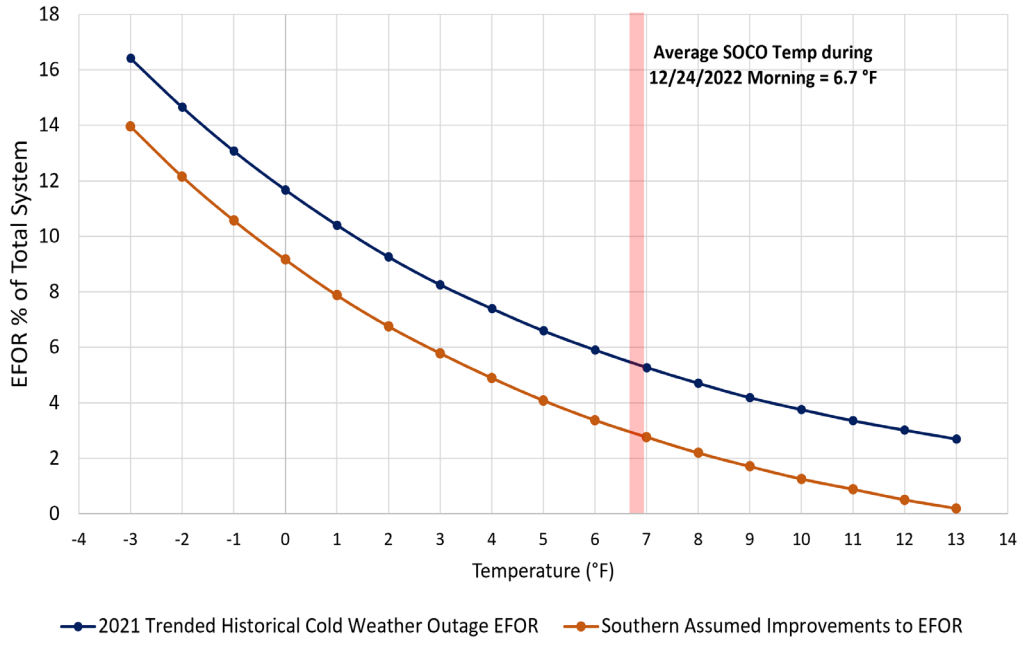


Figure 15. Incremental Equivalent Forced Outage Rate (EFOR) at the Total Southern Company System.

Given that Georgia Power alone experienced a 15% reduction in capacity due forced outages during the storm, the assumed incremental outage rates of 2.77% discussed above appear to significantly underrepresent winter outage risks for the system. Therefore, these assumptions should be revisited and results of the analysis should be transparent for stakeholders.

The challenges due to cold weather outages reinforce the need for all resources to be evaluated for their firm capacity contribution using probabilistic methods just like wind, solar, and battery storage.

As discussed, another issue is that the company-wide risk due to cold weather outages remains unclear since reported data is missing for Alabama, Mississippi, and Southern Power owned units and PPAs during the event. This report has estimated the performance of these plants, but actual detailed information is needed.

Furthermore, Georgia Power only provided information on outages that occurred on the peak load day of December 24, 2022. Extreme cold weather affected the entire region prior, during, and after the worst day while temperatures were still low, and the effects of cold weather outages could have occurred on other days than the peak day.

Performance of Renewable Resources

Figure 16 *(below)* illustrates the total generation from solar resources within the Southern Company balancing authority footprint during the storm. As expected, solar resources did contribute to meeting demand throughout the day, but in the early morning hours output was limited. Compared to other winter peak events, solar performance was generally stable, but its role in peak support remains constrained due to the lack of irradiance at critical morning and and

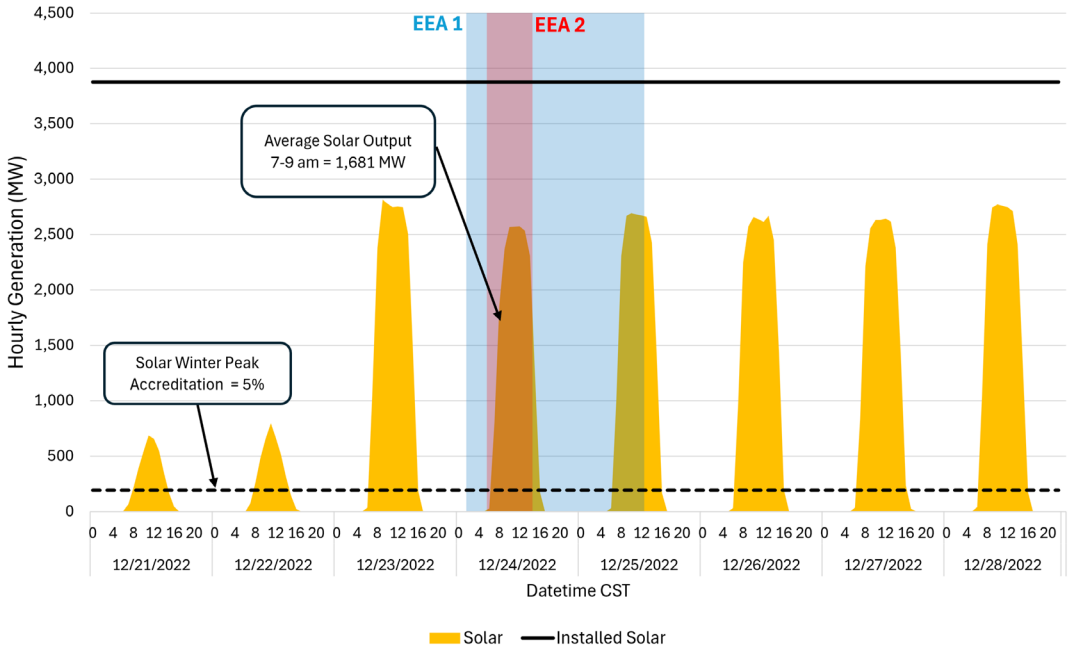


Figure 16. Solar generation for the entire Southern Company Balancing Authority during Winter Storm Elliott.

Month-Year	Peak Load Hour	Peak Load (MW)	Solar Capacity Factor at Peak
January 2019	1/30/19 6:00	40,450	1%
January 2020	1/22/20 6:00	40,410	1%
February 2021	2/17/21 6:00	40,922	4%
December 2022	12/24/22 7:00	45,131	21%
December 2023	12/20/23 7:00	37,890	23%
January 2024	1/17/24 6:00	47,368	2%

Table 3. Southern Company Balancing Authority solar capacity factor during historical peak load hours based on EIA data.

evening peaks. This shows that while solar production was low on the days leading up to the extreme cold event, production was high in the day prior to, and during, the event. This suggests that in the future, with increased battery storage resources, solar resources can improve reliability even if they are unavailable during the early morning peak load hours.

Table 3 *(above)* shows historical peak load and solar output relative to installed capacity for the 2019-2024 winter peak load events in the Southern Company Balancing Authority according to EIA 930 and EIA 860 data. Solar resources are not expected to contribute to winter peak load and utilities plan for this accordingly.

For example, the 2022 Georgia Power IRP evaluated the capacity accreditation for solar resources and determined their winter accreditation is 0-10% depending on the type of solar array and the penetration on the system[5]. Results in Table 3 and Figure 16 indicate that solar performed well above it's expected contribution during Winter Storm Elliott.

Other historical peak loads show performance can vary widely, largely driven by whether peak loads occur between 6-7 am based on the data shown. While solar generation during winter peak loads can vary, if battery storage resources are added alongside solar then greater utilization can be achieved, especially for early morning peak load hours in the wintertime. Currently, battery storage deployment is limited in Southern Company.

It is clear though that prior to the extreme events occurring on December 24, 2022, that storage resources could have been charged in advance to mitigate the hours of highest peak load enhancing resilience by rapidly offsetting unexpected generator outages and increasing system flexibility. Furthermore, solar, storage, and wind resources create portfolio effects that can boost the total renewable systems capacity accreditation. These effects should be evaluated and accreditation refined over time.

Recommendations to Improve Planning for Cold Weather Outages

The following are recommendations on how Southern Company and its subsidiaries can provide greater clarity on how the generation fleet performs under cold weather conditions and how to better represent the risks that all generation faces when planning for new generation resources to meet demand or replace retirements:

1. **Conduct transparent evaluation of how increases to power plant outages due to cold weather. Current information is from the Georgia Power 2022 IRP and only provides fleetwide incremental outages.**
2. **Assess whether assumed cold weather outage improvements in 2021 have been effective.**
3. **Assess all future resource addition options based on every resource type and its effective load carry capability (ELCC) like how wind, solar, and battery storage is assessed. This necessitates including cold weather outages in the assessment.**
4. **Provide transparency on the current capacity accreditation assumed for all resources. Historical accreditation using incremental capacity equivalent (ICE) is redacted in previous full IRP filings.**

5 2022 GPC IRP, Study of Renewable Capacity Values using the ELCC Methodology in the Southern Company System, December 2021.

Emergency Power Purchases and Costs

One key reliability feature of the bulk power system is the ability to import power from neighboring regions to alleviate stress during extreme events.

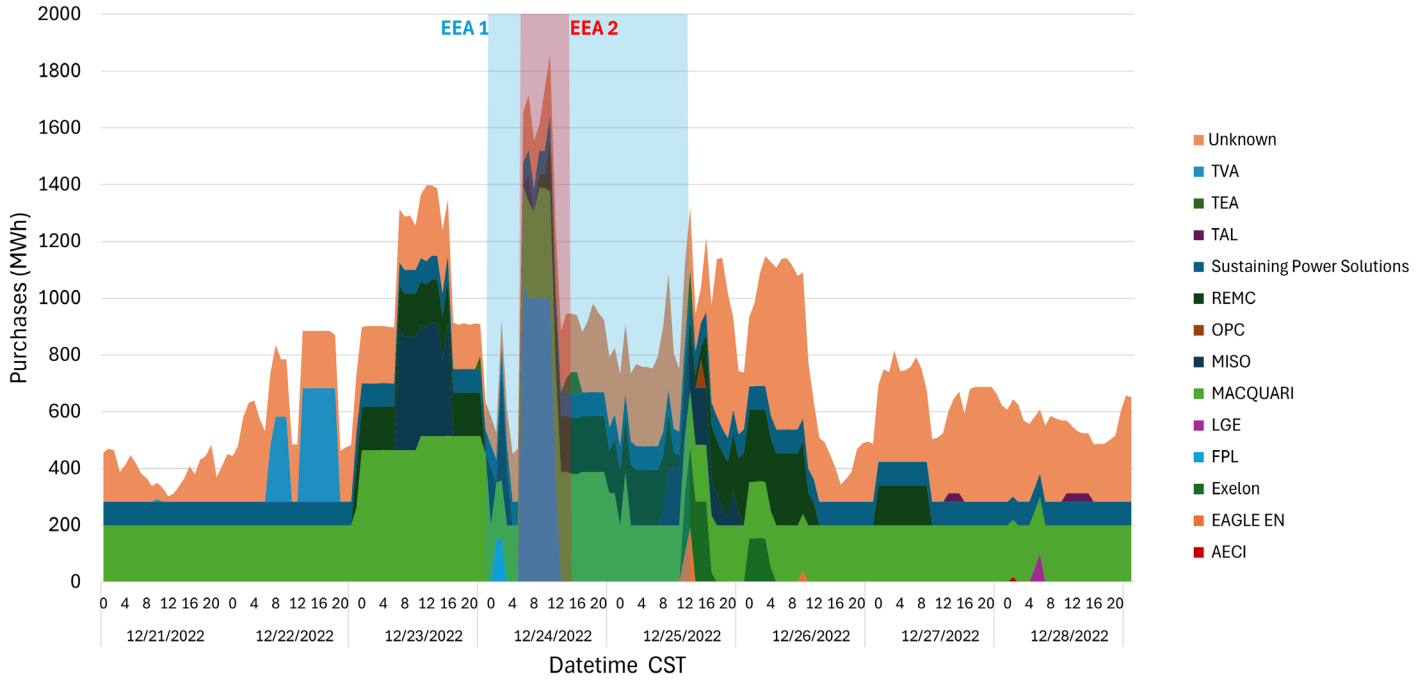


Figure 17. Winter Storm Elliott - Southern Company Known and Estimated Purchases by Source.

Even in vertically integrated areas like the Southeast, energy exchanges play a crucial role in balancing supply and demand and ensuring system reliability, especially during emergencies such as Winter Storm Elliott.

However, these regions typically lack transparency about where emergency power originates and its cost to customers, limiting public oversight of emergency spending and raising questions about planning for reliable external support an ensuring that prices are based in some transparent fashion.

In response to regulatory data requests, some data for Georgia Power was released, though comprehensive data for the full Southern Company system remains unavailable. By matching resource IDs and timestamps from Georgia Power with anonymized data from other Southern Company entities, it was possible to estimate the source, magnitude, and cost of emergency power for the broader system.

However, only Georgia Power Company transactions are shown with complete information regarding the source and price of power, while non-GPC transactions are based on estimations.

Figure 17 *(above)* displays all purchases by source including estimated and unidentified purchases for all Southern Company entities.

Note that outside of known balancing authorities, the exact power plants and owners are uncertain so additional tracking to what kind of units are providing the power is difficult to accomplish.

Price Variability by Seller and Estimated Costs

Throughout Winter Storm Elliott, prices varied significantly depending on the seller. This variation is expected during extreme events as regions experience fluctuating spare capacity. Figure 18 *(below)* illustrates the known and estimated costs of power purchased by Southern Company by seller, with unknown purchases estimated based on the average price for known purchases during each hour. In total, emergency purchases cost $51 million, or $350/MWh.

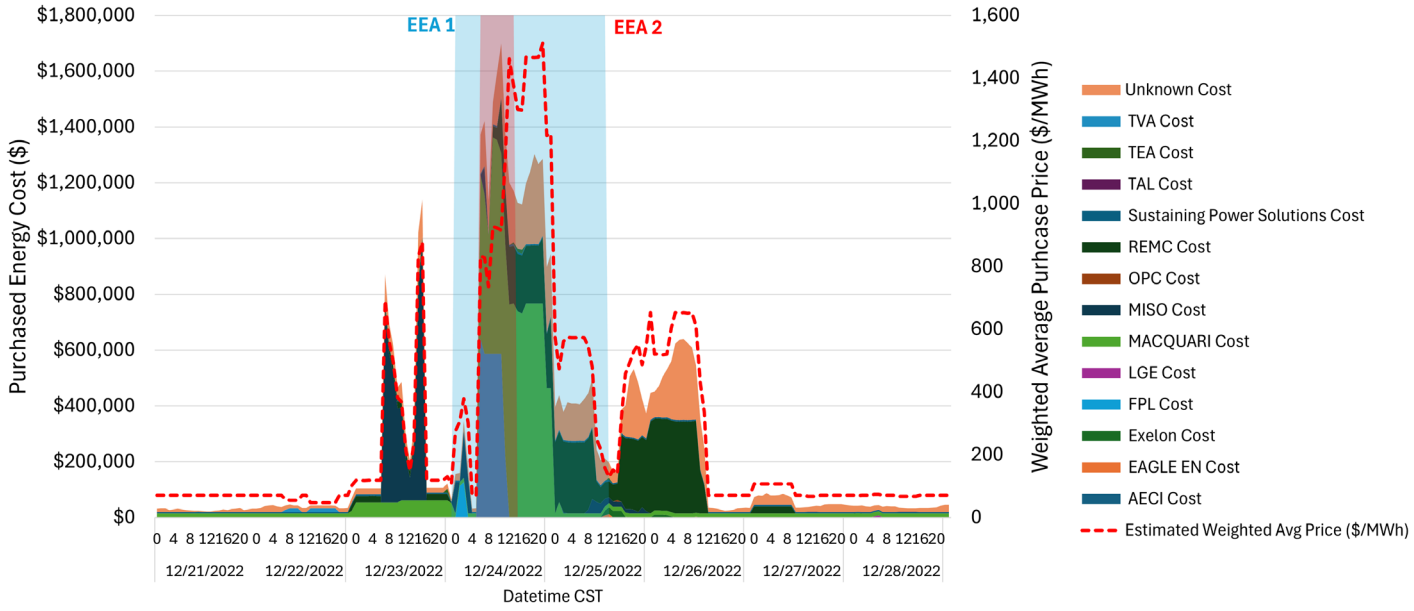


Figure 18. Winter Storm Elliot - Southern Company Estimated Cost by Source.

Table 4 *(page 20)* provides a summary of purchase data available via Georgia Power's discovery request, including estimates for all Southern Company purchases matched with GPC resource IDs, where prices for matched sellers were set to the GPC rate. For transactions labeled "unknown," no GPC resource ID was available for matching.

This summary highlights several points: while energy costs generally track with total MWh purchased, certain sellers exhibited disproportionately high prices. For instance, purchases from REMC, MISO, and FPL accounted for a much higher percentage of total costs compared to MWh purchased.

Specifically, REMC transactions represented only 9.9% of the total MWh but contributed 24.3% of total costs due to elevated prices that persisted well after EEA 1 and EEA 2 conditions had ended.

The price formation for non-market regions like MISO lack transparency, making it difficult to determine the reasons behind these elevated rates. It is expected that prices across the region will be high during the event.

But the reason some prices were $400/MWh versus $4,000/MWh is worth providing more detail on.

Other sellers also contributed to high overall costs, notably Macquarie and FPL. FPL provided 6,736 MWh at an average price of $599/MWh, reaching a peak of $1,000/MWh. Macquarie, supplying roughly 33% of Southern Company's total purchased MWh during the event, averaged $330/MWh, with some purchases reaching as high as $4,000/MWh during EEA 2.

Such data points suggest the potential for substantial savings if lower-cost alternatives were available and less market power given to emergency purchases by planning for a more resilient system.

Seller Name	Total MWh	% of Total MWh	Total Cost ($)	% of Total Cost	Average Price ($/MWh)	Max Price ($/MWh)
AECI	18	0.0%	$946	0.002%	$53	$54
EAGLE EN	331	0.2%	$22,015	0.04%	$67	$70
Exelon	2,045	1.4%	$160,005	0.31%	$78	$85
FPL	6,736	4.6%	$4,033,643	7.85%	$599	$1,000
LGE	146	0.1%	$12,182	0.02%	$83	$96
MACQUARI	48,596	33.2%	$16,053,050	31.24%	$330	$4,000
MISO	6,909	4.7%	$5,246,666	10.27%	$764	$2,832
OPC	100	0.1%	$6,000	0.01%	$60	$60
REMC	14,498	9.9%	$12,518,350	24.36%	$863	$1,300
Sustaining Power Solutions	15,936	10.9%	$987,235	1.92%	$62	$62
TAL	270	0.2%	$8,730	0.02%	$32	$36
TEA	357	0.2%	$56,714	0.11%	$159	$303
TVA	3,909	2.7%	$128,399	0.25%	$33	$44
Unknown*	46,633	31.8%	$12,118,397	23.58%	$260	$1,081
Total Purchases	146,484	100%	$51,382,333	100%	$351	$4,000

Table 4. Summary data by Southern Company during Winter Storm Elliott based on GPC Data (12/21/2022 - 12/28/2022).

Implications of Non-Transparent Price Setting

This review of emergency power purchases underscores the wide range of prices paid by Georgia Power to different sellers during Winter Storm Elliott, revealing challenges inherent in a system without transparent locational marginal pricing (LMP) for transactions in vertically integrated regions like the Southeast.

In contrast, neighboring regions impacted by Winter Storm Elliott, such as MISO, provide LMP data that reflects both energy production and transportation costs, including information on transmission congestion and losses.

Notably, MISO provides real-time price data at its interface with Southern Company in Mississippi, updated on a five-minute basis. This level of pricing transparency allows stakeholders to verify that prices reflect actual market conditions.

For Southern Company customers, the lack of similar transparency represents a challenge, particularly in the context of high emergency costs.

Currently, neither Georgia Power's public data nor the Southeast Energy Exchange Market (SEEM), reviewed in detail in the next section, offers information on price formation, especially under stress conditions.

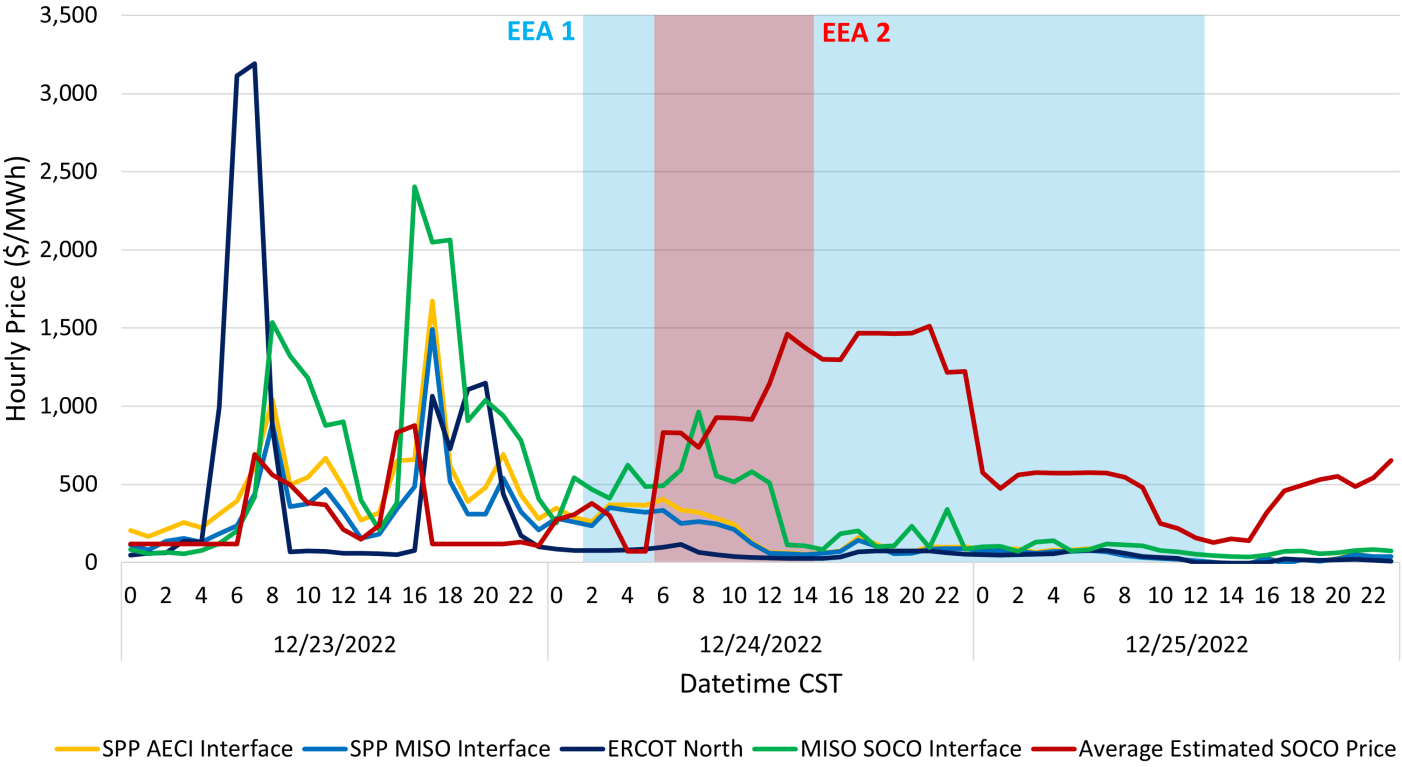


Figure 19. Average Known Southern Company Purchase Price vs Nearby Market LMP ($/MWh)

This limitation prevents customers from understanding the rationale behind emergency prices and assessing whether costs could have been mitigated through better planning or interregional coordination.

Opportunities for Interregional Transmission to Improve Reliability and Reduce Costs

Reviewing LMPs for nearby regions highlights potential cost savings and reliability benefits that increased imports from neighboring regions could provide if transmission were available.

Enhanced interregional transmission connections with transparent pricing could offer more reliable access to affordable external resources.

Figure 19 *(above)* shows that prices in ERCOT, SPP, and MISO (at the Southern Company interface) were considerably lower than GPC purchase prices on December 24 and 25, when generation weighted known prices averaged over $1,000/MWh.

Leveraging interregional transfers could thus help Southern Company meet peak demands more cost-effectively during future extreme events, while offering customers clearer insights into price formation.

Southeast Energy Exchange Market Performance

The Southeast Energy Exchange Market (SEEM) began operations in November 2022, just one month before Winter Storm Elliott stressed power systems across the Southeastern United States. SEEM was designed to facilitate voluntary bilateral energy trade across the region, providing participants with a way to exchange surplus energy efficiently.

However, during the critical hours of December 24th, 2022, when the Southern region declared EEA 1 and EEA 2 energy emergencies, publicly available data shows that no exchanges occurred among SEEM participants. This absence of trades highlights questions about SEEM's role in supporting reliability during peak demand events and the broader applicability of its platform under emergency conditions.

While SEEM data is anonymized, the platform generally shows transaction volumes across different periods, allowing observers to see broad trends without detailed participant information. Analysis of SEEM's transaction volumes during Winter Storm Elliott suggests low utilization by market participants at a time when system operators were under significant stress to maintain grid stability. This could be attributed, in part, to SEEM's novelty or uncertainty about the available capacity and pricing under extreme conditions.

However, low activity in SEEM during the storm aligns with the independent market auditor's reports[6], which indicate that SEEM transactions were limited during cold weather events, potentially due to limited availability of surplus energy and participant hesitancy during tight grid conditions. Despite SEEM's low trading volume during Winter Storm Elliott, bilateral transactions outside SEEM were still active across the region. Southern Company, for example, engaged in multiple direct purchases during this period, reflecting a preference for more established bilateral agreements rather than SEEM exchanges under emergency circumstances.

This trend indicates that SEEM's structure may not yet fully align with participant needs during stress events, when timely and cost-effective energy transactions are most critical.

SEEM Performance in Subsequent Winter Peak Events

Since Winter Storm Elliott, SEEM has continued operating through subsequent winter peak load events, but its performance under these conditions has similarly shown limited market activity during peak demand periods. This ongoing trend suggests that SEEM, while potentially valuable for regular trading, has not become a resource for emergency support during peak conditions such as those that occurred during Winter Storm Heather[7].

Furthermore, the anonymized structure of SEEM data limits participants and stakeholders from understanding price formation or the dynamics of energy exchanges during tight conditions, in contrast to organized markets like MISO or PJM, where locational marginal pricing (LMP) provides detailed price signals reflecting supply and demand fluctuations in real time.

In summary, SEEM's first significant test under Winter Storm Elliott highlighted critical limitations in the platform's ability to facilitate energy exchanges during emergencies.

Its low utilization during peak load events like Winter Storm Elliott and Winter Storm Heather calls into question its ability to aid the system in matching economic transactions during reliability events. As a result, SEEM may not yet be equipped to provide meaningful support for system operators or offer cost-effective, transparent solutions for ratepayers during critical grid conditions.

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6 Potomac Economics, Monthly Audit Report on the Southeast Energy Exchange Market - December 2022, January 31, 2023.
7 Potomac Economics, Monthly Audit Report on the Southeast Energy Exchange Market - January 2024, February 29, 2024.

Conclusion and Recommendations

This report examined Southern Company's generation fleet performance, load forecasting accuracy, and market transactions during Winter Storm Elliott. While Southern Company successfully managed the event without resorting to involuntary load shedding, the system operated under tight conditions, revealing areas where improvements in resource reliability, forecasting, and market transparency could enhance resilience against future weather-related stress.

Additionally, the Southeast Energy Exchange Market (SEEM), which had launched only a month earlier, showed minimal trading activity, highlighting opportunities for enhancements to support reliability during emergencies. Questions remain regarding how the system might have performed if demand had been higher, such as on a non-holiday weekday when electricity use is typically greater.

These considerations underscore the need for a deeper examination of how risk is evaluated in system planning and how potentially high-value opportunities to mitigate risk from extreme weather (such as by improving energy efficiency and increasing access to interregional resources) are assessed. This is of particular importance for extreme winter events which have high uncertainty on both generator outages and electricity demand.

To address these challenges, the following actions would benefit both Southern Company and stakeholders in improving transparency and ensuring reliability.

1. **Enhance Thermal Resource Evaluation:** Future grid planning should improve methods for evaluating the capacity contribution of thermal resources. Rather than discounting by average forced outage rates, planning should reflect the real correlated outage risk of these resources during extreme events. Consistent with the evaluation approach for wind and solar resources, this revised methodology would provide a more accurate picture of available capacity during winter peak demands and extreme weather events.

2. **Reassess Incremental Cold Weather Outages:** Southern Company should re-evaluate incremental cold weather outage assumptions, disaggregating data by fuel type rather than applying fleet-wide assumptions. Analyzing outage probabilities by fuel type could highlight distinct vulnerabilities and more accurately inform resource adequacy planning for cold weather conditions.

3. **Increase Transparency:** Southern Company should establish more transparent mechanisms for purchased power and emergency cost formation. Adopting some form of locational marginal pricing (LMP) across the Southern Company territory would align emergency prices with real-time market conditions, offering regulators and customers a clearer understanding of cost drivers during emergencies as they relate to both the price of energy and the cost of transmission.

4. **Enhance SEEM Functionality and Transparency:** Based on SEEM's limited use during Winter Storm Elliott, improvements should be considered to enhance its role in reliability. The platform could incorporate faster price signaling or offer day-ahead market signals to increase utilization during peak events. Recommendations already exist from the SEEM independent auditor to improve performance. Current reviews of SEEM by FERC also offer a chance to improve operations during emergencies, particularly with external regions into SEEM.

5. **Evaluate interregional transmission opportunities to mitigate winter reliability risks by accessing low cost and uncorrelated resources in external regions.** It is well documented that interregional transmission can provide substantial resource adequacy and resilience benefits. Long-term and multi-value transmission planning should be adopted in the region.

6. **Evaluate targeted energy efficiency opportunities to reduce load and volatility during cold weather events, including building envelope efficiency improvements and more efficient heating programs to mitigate winter load volatility.**

By implementing these recommendations, Southern Company and its stakeholders can strengthen reliability, ensure resource adequacy, and reduce costs under extreme weather conditions. A focus on accurate resource evaluation, refined forecasting, and transparent pricing mechanisms will better equip the region to manage future winter peak events effectively.



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SREA EXHIBIT AP-3:

J. Michael Hagerty, Peter Heller & Evan Bennett, Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy, Brattle, (2025)

Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy

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APRIL 2, 2025

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PREPARED FOR

CCEBA Carolinas Clean Energy Business Association

CEBA Clean Energy Buyers Association

SOUTHERN RENEWABLE ENERGY ASSOCIATION

Paid for by the Clean Grid Initiative, a project of Multiplier

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- The authors would like to acknowledge the valuable contributions to this report provided by Hannes Pfeifenberger and John Tsoukalis (The Brattle Group), Gary Moody (Clean Grid Initiative), Simon Mahan (SREA), Katie Southworth (CEBA), Chris Carmody (CCEBA), Daniel Tait (Energy Alabama), and Jill Kysor (Energy Foundation). However, all results and any errors are the responsibility of the authors.
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Executive Summary



Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

Facing unprecedented load growth and increasing reliability risks, Southeast utilities need to invest in their regional transmission systems to improve reliability and reduce costs.

- **4x Increase in Transmission Costs over Last 20 years:** Spending on utility-specific upgrades increased during a period of moderate load growth due to aging infrastructure and new generation capacity needs
- **20 GW of Load Growth in Next 10 Years:** Serving the rapid 25% increase in load cost-effectively requires identifying opportunities for regional projects to supplement local upgrades and reduce system costs
- **80 GW of New Generation to Serve Load:** New generation (gas, solar, and storage) faces cost & schedule risks due to limited transmission capacity, which can be mitigated by proactive regional upgrades
- **Increasing Severity & Frequency of Winter Storms:** Winter storms have created new reliability risks over last 5 years that drive a need for both regional and interregional upgrades

Recent national studies find a significant need for new regional transmission across the Southeast.

Yet, all recent Southeast transmission upgrades are based on utility-specific local transmission planning* that has not considered the benefits of supplementing local upgrades with larger, more cost-effective regional and interregional transmission projects.

*In some portions of the Southeast (e.g., GA, NC, and SC), utilities within the same state collaborate on "local" reliability-driven transmission planning for their service territories.

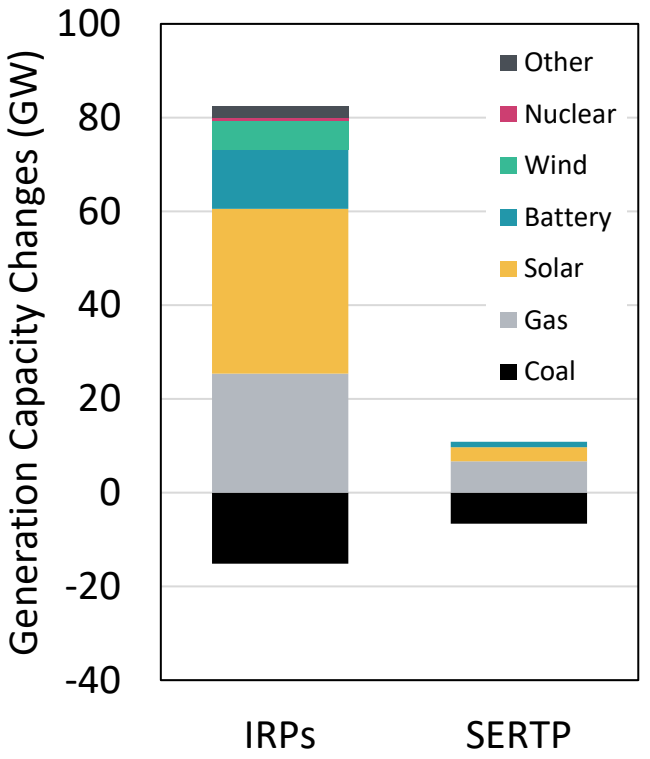
Existing Regional Planning Process Results in Insufficient Investment in the Regional Transmission Network

Southeastern Regional Transmission Planning (SERTP) completes an annual "bottom-up" regional planning process that has several limitations for identifying beneficial regional upgrades.

- **Limited Scope**: SERTP aggregates local planning studies and confirms regional reliability for a single future load scenario, failing to utilize scenarios developed in Sponsors' resource planning studies
- **Inconsistent with IRPs**: SERTP studies include just 12% of the 80 GW of new generation identified as needed by the most recent IRP studies
- **Lack of Transparency:** SERTP provides limited information on transmission costs, violations, or alternatives studied to meet needs
- **No Regional Projects Approved**: SERTP analyzes regional alternatives based on a limited set of system needs, resulting in no regional upgrades in 11 years of SERTP regional planning studies

Existing SERTP planning process will not identify and approve the most cost-effective transmission infrastructure to reliably serve future load

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



Recommendations to Enhance SERTP Regional Planning that will Reduce Costs and Increase Reliability of the Southeast Grid

Exhibit AP-3

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

I. Improve Existing Planning Process

1. **Increase transparency** of study assumptions, approach, and results
2. **Engage state commissions and energy agencies** to participate in process and ensure results reduce costs and address state policies
3. Expand solutions studied to reflect **least-cost transmission "loading order"** that maximizes existing grid, upgrades existing lines, and builds new lines where necessary

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 **region-wide production cost model**
6. Develop guidelines to evaluate a **comprehensive set of cost savings and 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**

Case Study: SERTP-Identified Upgrades Reduce Costs

To demonstrate the value for regional transmission, we performed a high-level analysis of three 500 kV upgrades SERTP identified in its 2024 process based on historical data.

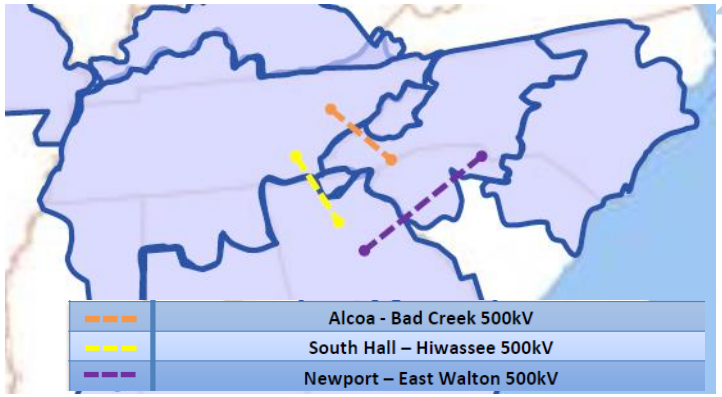
We estimated $8 billion of benefits compared to $5 billion in costs, resulting in at least $3 billion of net benefits

- Production cost savings: $2.9 billion (*range*: $2.0–3.6 billion)
- Load diversity cost savings: $3.3 billion (*range*: $0.9–6.0 billion)
- Resilience benefits: $1.6 billion (*range*: $0.7–2.3 billion)
- Additional potential benefits: avoided reliability and interconnection upgrade costs, greater production cost savings with increased solar/wind additions and reduced generation costs

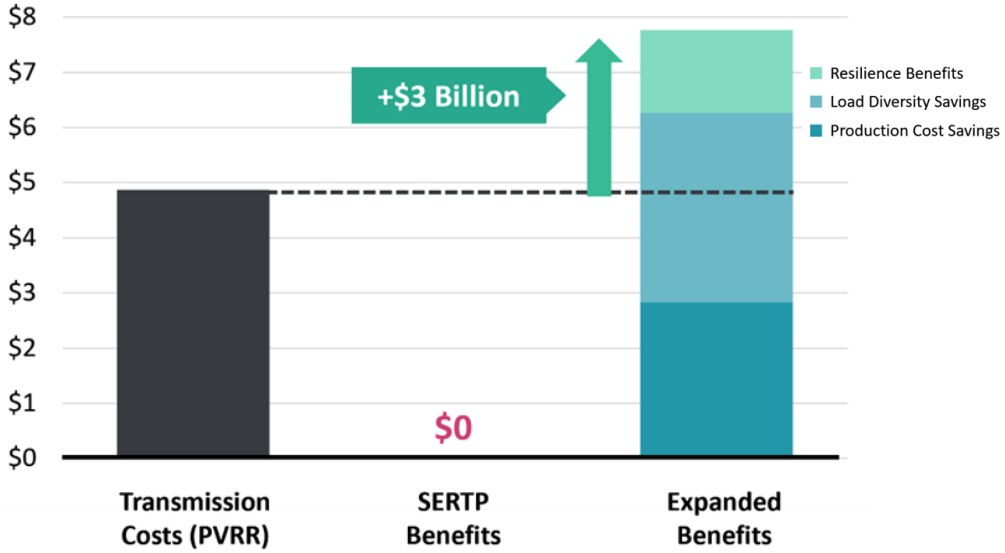
Regional transmission can reduce system costs when a broader scope of cost savings and other benefits are analyzed

By contrast, SERTP's very narrow view of benefits based solely on avoided local transmission costs identified no cost savings

SERTP-Identified Regional Projects



Estimated Net Benefits of Regional Projects



Order 1920 Provides Southeast Opportunity in 2025 to Enhance its Regional Transmission Planning Process

- **Southeast is the only major U.S. region that has not pursued significant regional transmission projects over the past decade**
- **The lack of proactive regional transmission planning process results in higher costs, lower reliability, and delays in serving growing load due to insufficient grid infrastructure**
- **FERC issued Order No. 1920 last year that requires SERTP to implement a proactive, long-term, multi-value regional planning process, presenting a pivotal opportunity for the Southeast to align its regional transmission planning with industry best practices developed over the past 10–20 years**
- **The Southeast should embrace this opportunity in 2025 to modernize SERTP's regional transmission planning to build a stronger, more efficient grid that supports economic growth, energy affordability, and long-term resilience**

Report Contents

I. The Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

II. SERTP Regional Transmission Planning Process Is Insufficient to Meet Future System Needs

III. Recommendations to Enhance SERTP Regional Transmission Planning

IV. Why the Southeast Needs to Modernize Its Regional Planning Process Now to Reduce Costs and Increase Reliability



I. The Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability



Southeast Needs to Invest in its Transmission Infrastructure

Facing unprecedented 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
- In-kind replacements will miss opportunities to more cost-effectively expand system capabilities
- 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

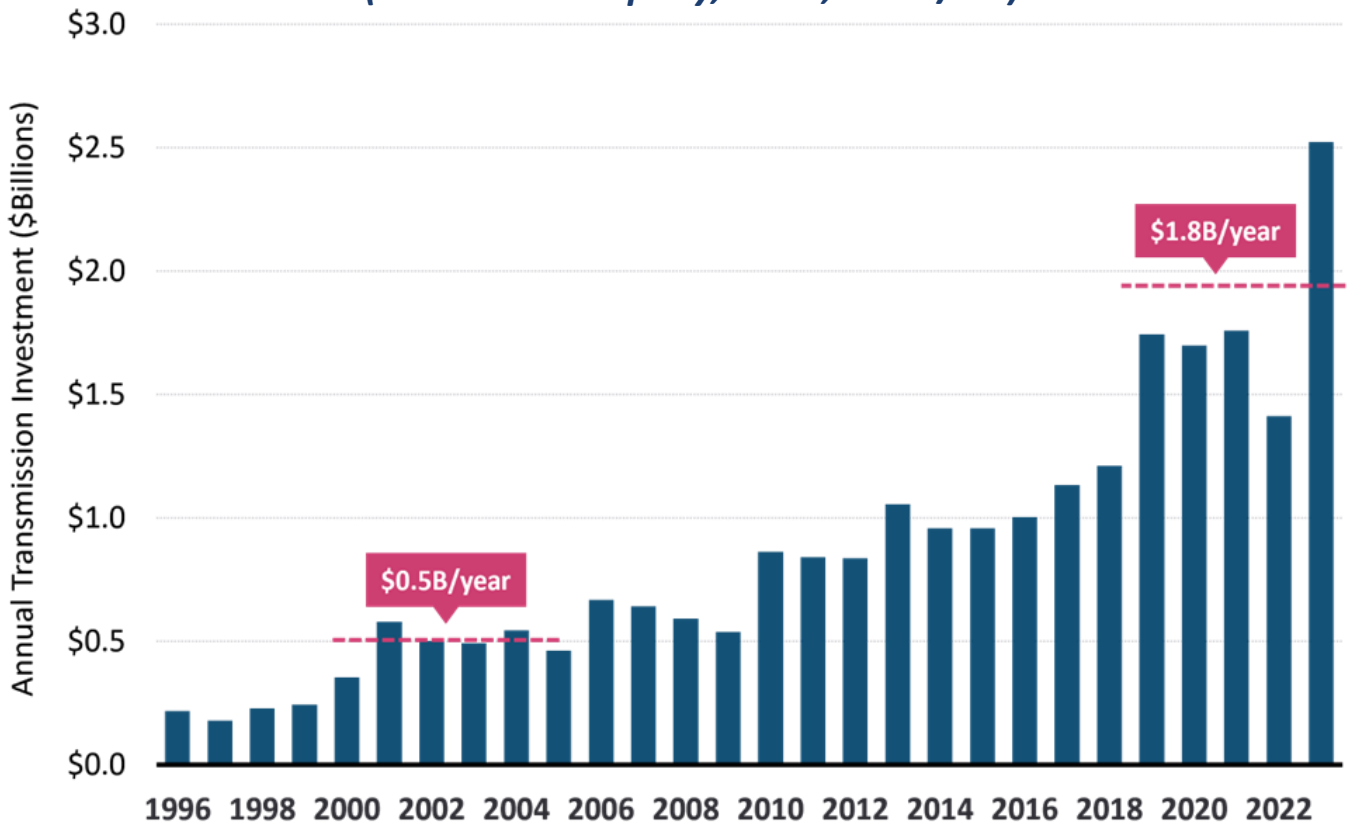
4x Increase in Reliability-Driven Local Transmission Needs

Transmission investment of three major 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 U.S.) have been driven by utility-specific projects* to support limited load growth, replace aging infrastructure, and interconnect new generation, driving up transmission rates
- Southeast utilities risk inefficiently investing in lower-value projects in the absence of a regional forward-looking strategy to maximize the value of its future grid investments

*In some portions of the Southeast (e.g., GA, NC, and SC), utilities within the same state collaborate on "local" reliability-driven transmission planning for their service territories.

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



Source: Analysis of FERC Form 1 Data

Transmission Needed to Serve 21 GW of Load Growth

Southeast utilities are projecting **21 GW (+25%) of load growth by 2035** in their resource planning studies due to new data centers and manufacturing facilities, equivalent to adding twice New York City's power demand in 10 years.

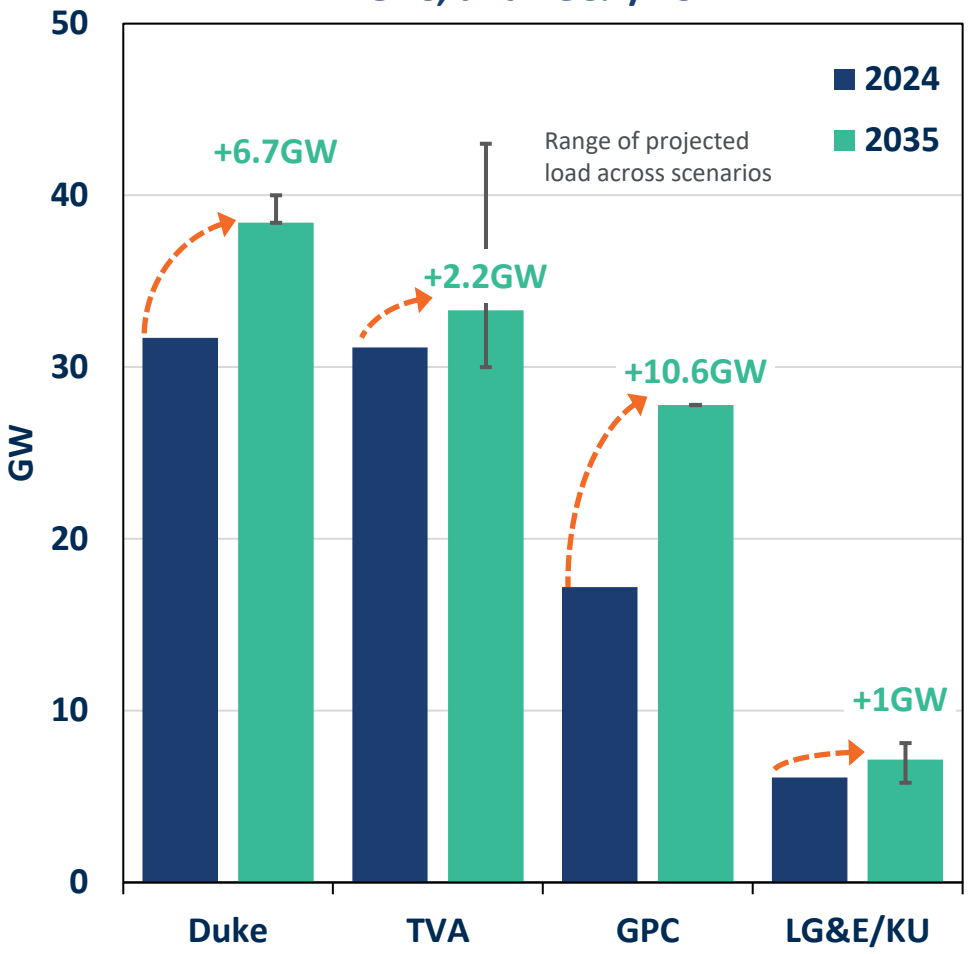
- Duke Energy: +7 GW to +9 GW
- TVA: +1 to +12 GW (base: 2 GW)
- Georgia Power (GPC): +11 GW

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

Transmission studies recently identified large-scale regional upgrades needed for cost-effectively supporting large load additions in Texas ($32 billion) and Mid-Atlantic ($6 billion).

Sources: ERCOT 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison; PJM Board Approves New Transmission Projects To Support Grid Reliability

Projected Load Growth by 2035 in Duke, TVA, GPC, and LG&E/KU



Sources: Duke 2023 2023 Carolinas Resource Plan Supplemental Planning Analysis; TVA 2025 Draft IRP; Georgia Power Company 2025 IRP; LG&E/KU 2024 IRP Volume I

Transmission Upgrades De-Risk New Generation Additions

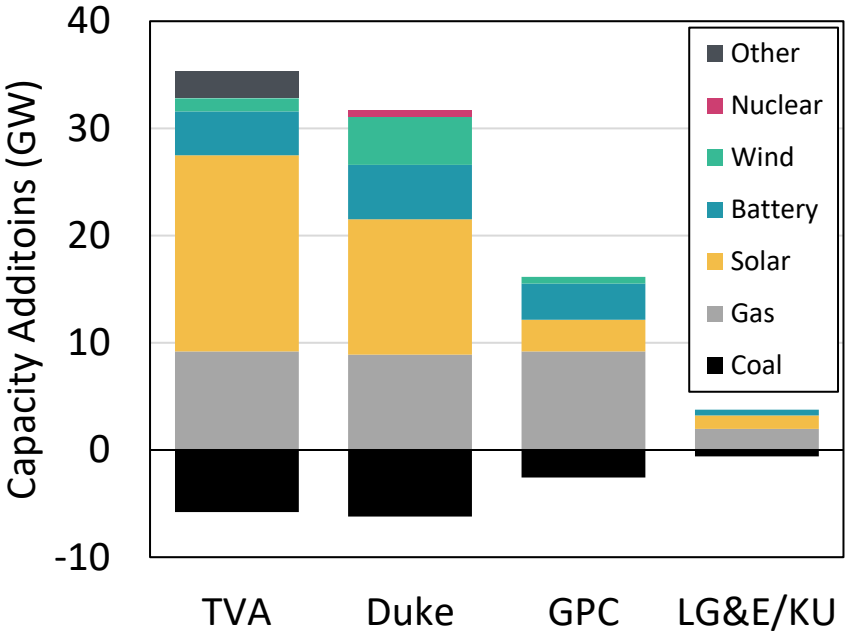
Southeast utilities' resource planning studies demonstrate the need to build and interconnect **more than 80 GW of new generation capacity** by 2035, or 8 GW per year.

- For context, the new Vogtle nuclear units added 3 GW to the grid
- New generation requires significant time to identify and construct network upgrades prior to interconnection
- Changing generation types and locations are shifting flows across the grid and increasing regional transmission needs

Without a stronger regional grid, new generation could face delays that increase energy prices and slow economic growth.

Yet Southeast utilities do not study regional upgrades to support the future generation mix; instead, higher-cost network upgrades will be identified on a just-in-time basis through generator interconnection studies.

New Generation Additions in Recent IRPs



Sources: TVA 2025 Draft IRP; Duke 2023 2023 Carolinas Resource Plan Supplemental Planning Analysis; Georgia Power Company 2025 IRP Technical Appendix Vol II ("Resource Mix Study"), Capacity Expansion Plans; LG&E/KU 2024 IRP Volume I

Regional Transmission Reduces Risks of Extreme Weather

In addition to load growth and new generation, recent extreme weather events have stressed the Southeast grid and lead to reliability events that could have been avoided with increased regional and interregional 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:

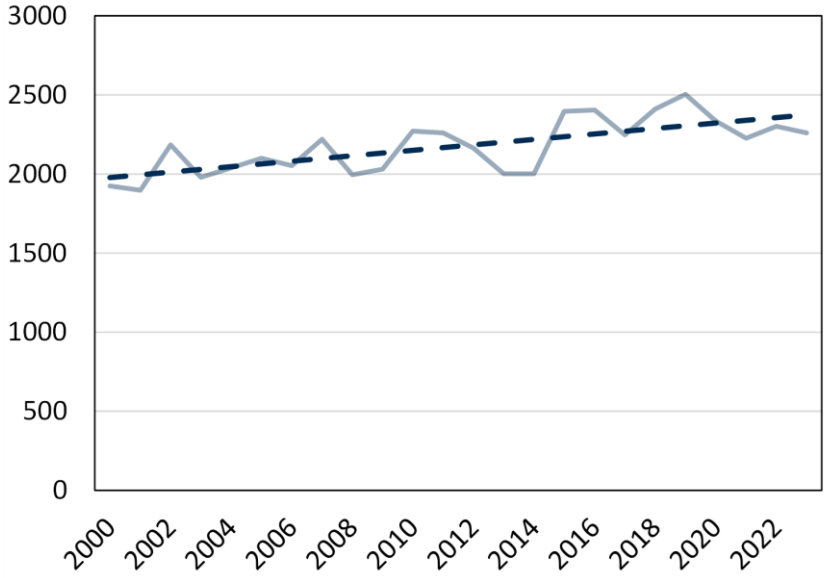
- DEC and DEP: Approximately 5,000 MWh over four hours
- TVA: Approximately 19,000 MWh over seven hours
- LG&E/KU: Approximately 1,200 MWh over four hours

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

As summers get warmer and winters storm increase, regional planners need to consider extreme conditions in future planning.

Regional and interregional transmission is an insurance policy against future extreme conditions, such as winter storms, heat waves, and renewable droughts, etc., providing access to a wider set of generation to serve load that increases reliability and reduces cost risks for customers.

Change in Cooling Degree Days for the South Atlantic Division



Sources & Notes: EIA Monthly Energy Review, January 2025. Population-weighted degree days are used by the EIA to model and forecast energy consumption.

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

Investing in Regional Transmission Reduces Total System Costs

Regional transmission can significantly reduce costs across the power system in excess of the incremental costs of the transmission solutions, resulting in lower total costs of serving demand.

The most significant drivers of cost savings from regional transmission projects include:

- **Production cost savings**: Reduce operational costs by increasing access to lower cost, more efficient generation resources, especially during heat waves, major generation and transmission outages, etc.
- **Lower energy losses**: Reduce operational costs by offloading highly utilized lines and reducing energy losses, and reduce capacity costs due to lower on-peak energy losses
- **Local transmission and interconnection cost savings**: Reduce costs of lower voltage local reliability projects needed for serving load, replacing aging infrastructure, or interconnecting new generation when regional plans are effectively developed and implemented
- **Generation capacity cost savings**: Reduce costs of new capacity to meet reserve requirements by taking advantage of load diversity between utilities across the region

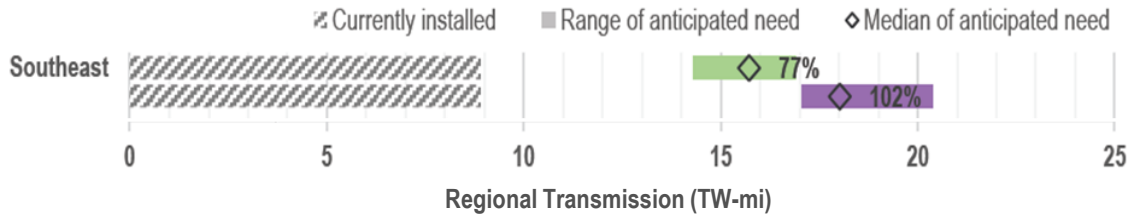
In the past 3 years, MISO approved $33 billion of regional projects that will **reduce net system costs by $50–125 billion** over the life of the assets based on a broad view of transmission cost savings.

Source: MISO, Long Range Transmission Planning, accessed February 2025.

Southeast Transmission Needs Highlighted in National 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**.

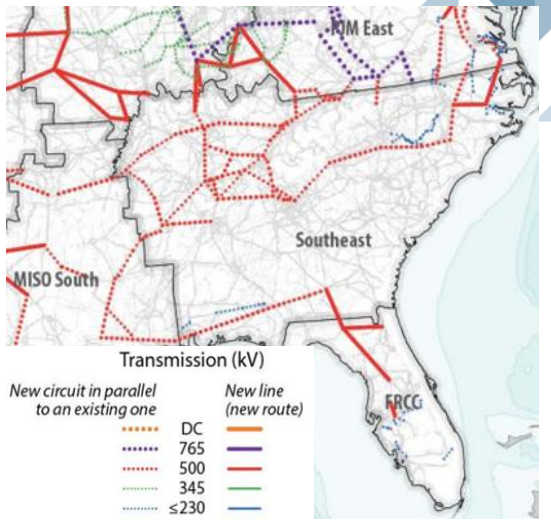


Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.

Source: National Transmission Needs Study

National Transmission Planning Study (2024)

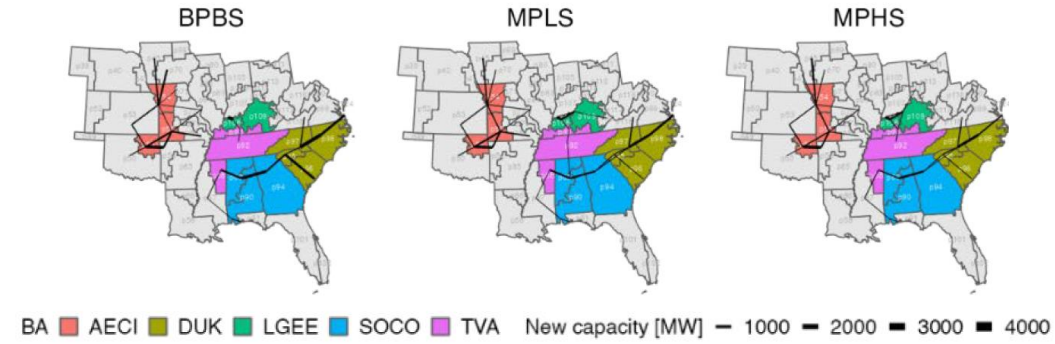
Conducted zonal capacity expansion and RA modeling through 2050 under 96 scenarios. Mid-demand, 90% emissions reduction AC scenario **strengthens existing 500 kV networks and connects SERTP to the Midwest and Plains through 345 kV and 500 kV lines** to enable flows across north-south and west-east interfaces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



Source: National Transmission Planning Study

NREL/LBNL Solar and Storage Integration Study (2024)

Investigates higher levels of solar and storage on transmission needs by 2035 and benefits of increased operational coordination among utilities. In lower-solar scenarios, **transmission additions added east-west regional capacity.**



Source: Solar and Storage Integration in the Southeastern United States

NERC Interregional Transfer Capability Study (2024)

Analyzed transfer capability between neighboring regions and recommended "prudent" interregional additions to maintain reliability. Identifies 4.1 GW of transmission into SERC-E (NC/SC) from other Southeast regions and PJM by 2033 **justifiable based on reliability alone** to alleviate resource deficiencies.

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)

Source: Interregional Transfer Capability Study (ITCS)

Southeast Can Build on Order 1920 to Improve Regional Planning

In 2024, the Federal Energy Regulatory Commission (FERC) issued Order No. 1920 to improve long-term regional transmission planning and cost allocation by proactively planning for regional grid needs based on industry-wide best practices implemented across the country.

Southeast utilities will need to update their 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

Order No. 1920 provides the Southeast an opportunity in 2025 to implement a new regional transmission planning process that will modernize its transmission network.

II. SERTP Regional Transmission Planning Process Is Insufficient to Meet Future System Needs



Who Is SERTP?

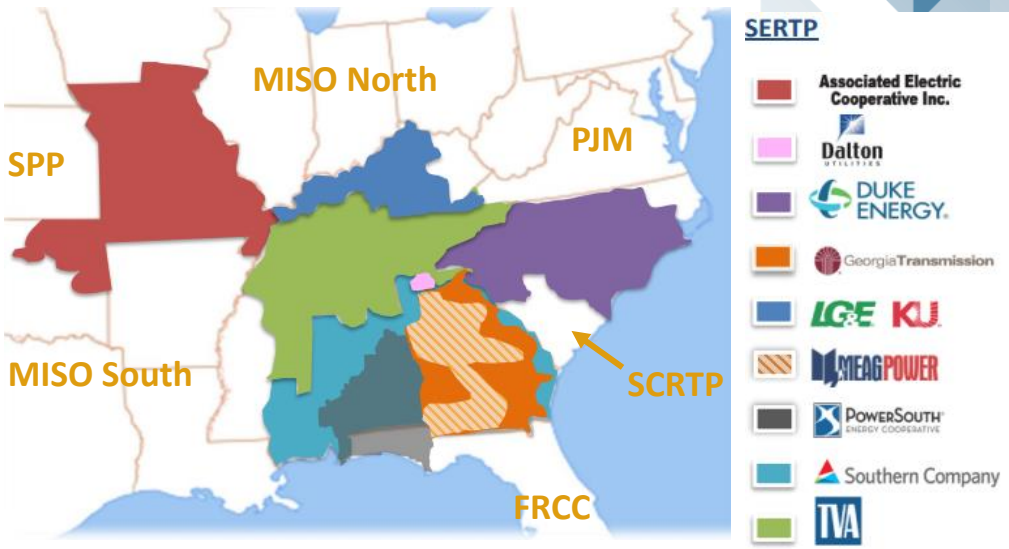
The Southeast Regional Transmission Planning (SERTP) was formed in 2007 to comply with FERC Order No. 890 by Southeast transmission providers (or "Sponsors").

- There are currently 10 Sponsors spanning 12 states
- South Carolina Regional Transmission Planning (SCRTP) members expected to join SERTP in 2025
- SERTP process was updated in 2015 to meet Order 1000 regional/interregional planning requirements

SERTP is a forum for Sponsors to collaborate on regional planning and cost allocation and has no independent SERTP staff beyond the utility Sponsors.

SERTP produces a Regional Transmission Plan each year that primarily reflects the aggregated 10-year local transmission plans provided by each Sponsor.

SERTP Regional Footprint



SERTP Sponsors' Peak Demand

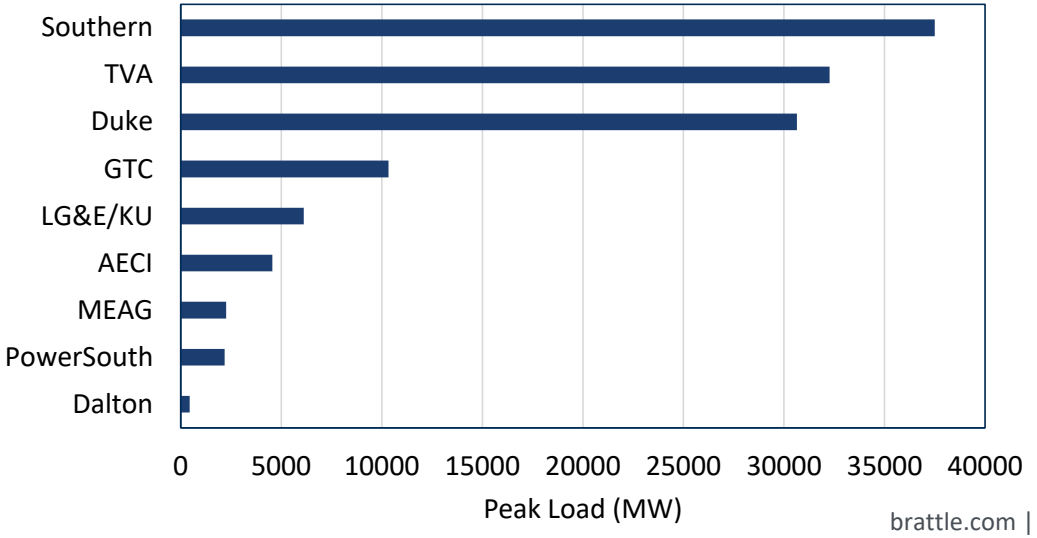


Image Source: SERTP - 1st Quarter Meeting (southeasternrtp.com). March 19th, 2024.

SERTP Produces an Annual 10-Year Regional Transmission Plan

In the annual regional planning process, SERTP Sponsors aggregate local plans into a preliminary expansion plan and assess whether regional projects meet reliability criteria at lower cost than local projects.

- SERTP hosts 4 meetings in each annual planning cycle to present their progress and allow for stakeholder input
- Stakeholders can request SERTP to study regional "economic" and "policy" needs and identify required upgrades

(1) Sponsors' Local Transmission Plans (Feb.–Jun.)

- Developed by each Sponsor or load serving entities (LSEs) in the 7 BAAs

(2) SERTP Preliminary Expansion Plan (Apr.–Jun.)

- "Bottom-Up Reliability Study Process" based on local transmission plans to identify any regional reliability constraints
- Evaluation of stakeholder-submitted public policy requirements

(3) SERTP Regional Planning Analyses (Sep.–Nov.)

- Evaluation stakeholder-requested economic planning studies
- Analysis of regional projects identified to be potentially more efficient or cost effective

(4) SERTP 10-Yr Regional Transmission Plan (Oct.–Dec.)

- "Snapshot" of transmission plan presented at the Annual Transmission Planning Summit

Source: 2024 2nd Quarter SERTP Meeting Presentation (southeasternrtp.com)

Regional Transmission Planning vs. Local Planning and IRPs

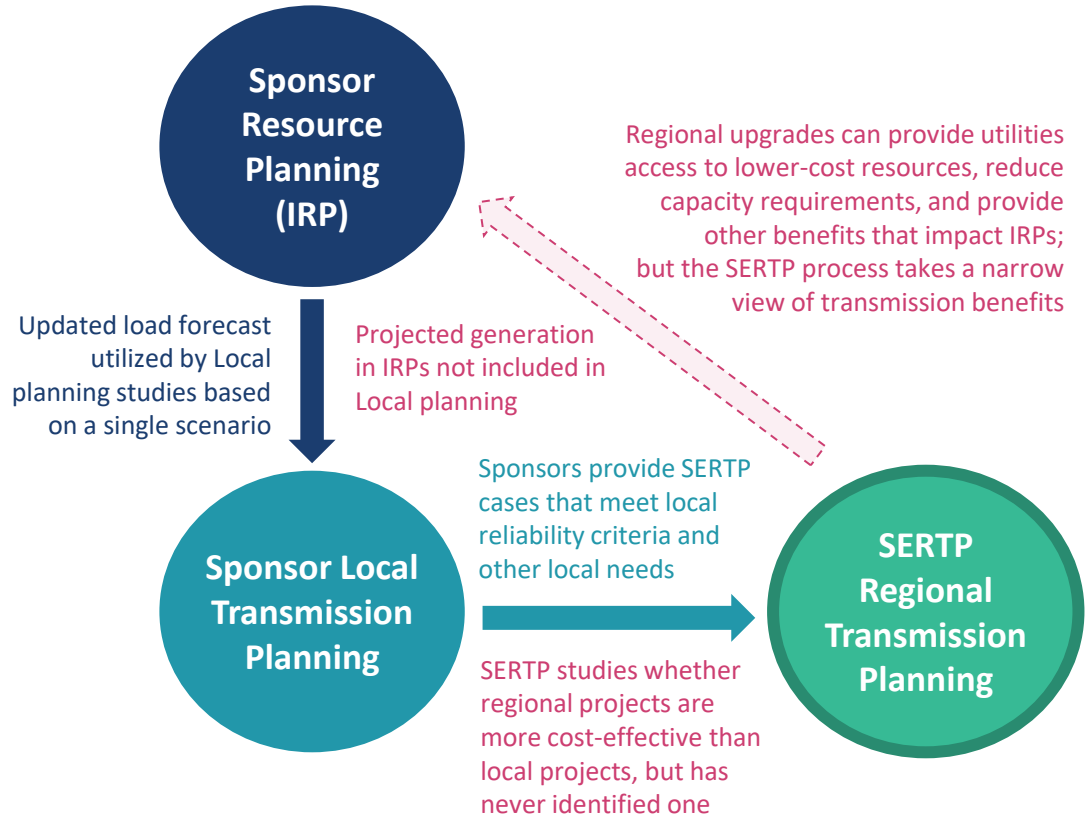
SERTP's planning models reflect system conditions studied in each Sponsor's local transmission planning study, not a consistent regional view of future system conditions.

- Each Sponsor completes local transmission planning studies that incorporate the latest load forecast but only a limited set of new generation resources and retirements
- Sponsors identify local upgrades to resolve reliability violations based on NERC criteria* and provide those cases to SERTP

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

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

Coordination across Resource Planning and Transmission Planning Studies



* Duke recently began studying several future scenarios and multi-value upgrades via the CTPC MVST local planning process (as summarized later in the slides), but has not yet completed it first MVST study.

SERTP Assumptions Not Aligned with Local Resource Planning

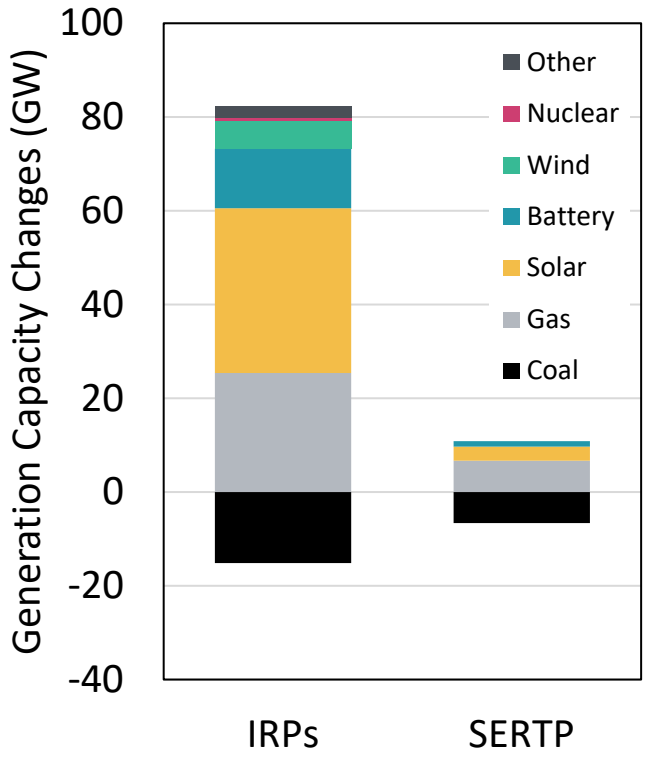
SERTP models regional system conditions for a single future scenario based on Sponsor-specific assumptions that are not aligned with the Sponsors' own resource planning studies.

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

- SERTP model only includes 10 GW of the 80 GW of new generation resources identified in the latest IRPs by 2035 (12%), including just 8% of solar additions, 27% of gas additions, and 41% of coal retirements
- In some cases, utilities are not including resources that they already requested approval from its state commissions for construction
- In some regions, SERTP includes hypothetical "proxy units" to ensure there are sufficient resources to meet load, instead of utilizing IRP portfolios

SERTP's single future scenario does not utilize the future scenarios developed in each Sponsor's resource planning studies to assess how the regional system could adapt to uncertainties in future changes (e.g., high growth scenarios or alternative generation resource mixes).

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



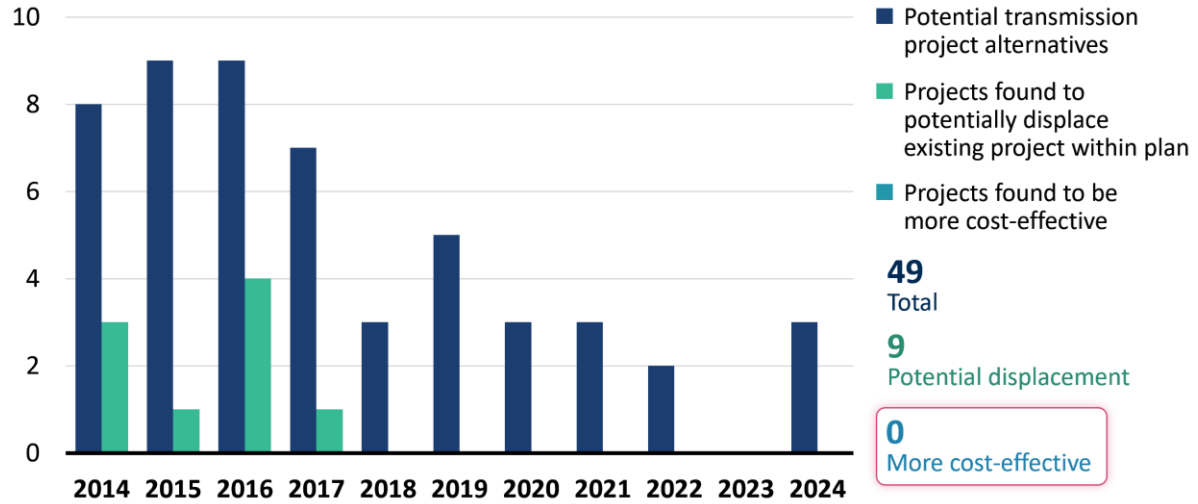
SERTP Has Not Identified Cost-Effective Regional Projects

Based on 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.

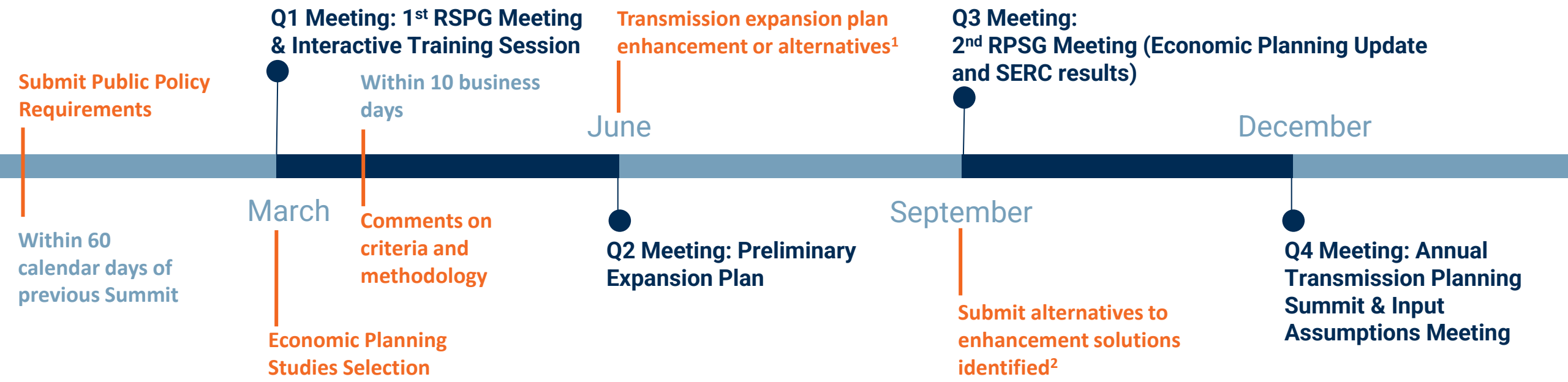
Potential Transmission Project Alternatives Evaluated by SERTP



SERTP Stakeholders Can Request Economic & Policy Studies

SERTP completes economic planning studies and an assessment of public policy requirements (PPRs) submitted by stakeholders in the Regional Planning Stakeholder Group (RPSG)

- SERTP may review up to 5 economic studies each year; stakeholders responsible for costs of additional studies
- Stakeholders can provide additional comments to SERTP at several points of the process, as noted below



[1] Preliminary transmission expansion plan will be posted on the **secure/CEII area** of the Regional Planning Website at least 10 calendar days prior to the Preliminary Expansion Plan meeting. Gaining access to the secure/CEII information is a process requiring background checks, $280 in fees, and executing a restrictive NDA.

[2] Preliminary economic planning study results posted 10 calendar days prior to the 2nd RPSG meeting. Stakeholders have 30 calendar days after the meeting to submit alternatives.

Source: Duke Joint OATT, Attachment N-1. Joint_OATT.pdf (duke-energy.com)

Economic Requests for <4 GW Identify Limited Regional Needs

SERTP economic studies analyze stakeholder requests for regional bulk power transfers and identify the least-cost upgrades required to enable those transfers while maintaining reliability.

- SERTP economic studies do not represent a commitment to proceeding with recommended enhancements
- Studies provide costs to entities seeking service across SERTP, which informs their decisions to pursue regional transfers, but does not consider a broader set of cost savings to SERTP customers

Amongst requests for 500 MW - 4,000 MW of transfers, SERTP identified limited upgrades (<$100 million), demonstrating that there is available capacity to accommodate incremental regional flows in this range.

2023 and 2024 SERTP Economic Study Results

Project No.	Year & Load Level	Source	Sink	Transfer Amount *MW*	Costs *$ Million*	*$/kW*
1	2028 - Winter Peak	MISO	TVA	2900	$21.5	$7.4
2	2028 - Summer Peak	South Georgia	North Georgia	1600	$95.9	$59.9
3	2028 - Summer Peak	TVA	North Georgia	1600	$56.5	$35.3
4	2028 - Summer Peak	MISO	LG&E/KU	1242	$83.5	$67.3
5	2033 - Summer Peak	SOCO	DEC	500	$0.0	$0.0
6	2029 - Summer Peak	MISO South/FRCC	SOCO	4000	$1.9	$0.5
7	2026 - Summer Peak	PJM	DEC/DEP	2000	$7.0	$3.5
8	2034 - Summer Peak	MISO North	SOCO	10000	$4,607.9	$460.8
9	2029 - Summer Peak	SPP/MISO North	AECI	2500	$0.0	$0.0
10	2034 - Winter Peak	DEC/SOCO	Santee Cooper	2400	$24.3	$10.1

Sources: SERTP 2024 Economic Planning Study Final Results
SERTP 2023 Economic Planning Study Final Results

2023 and 2024 SERTP Economic Study Requests

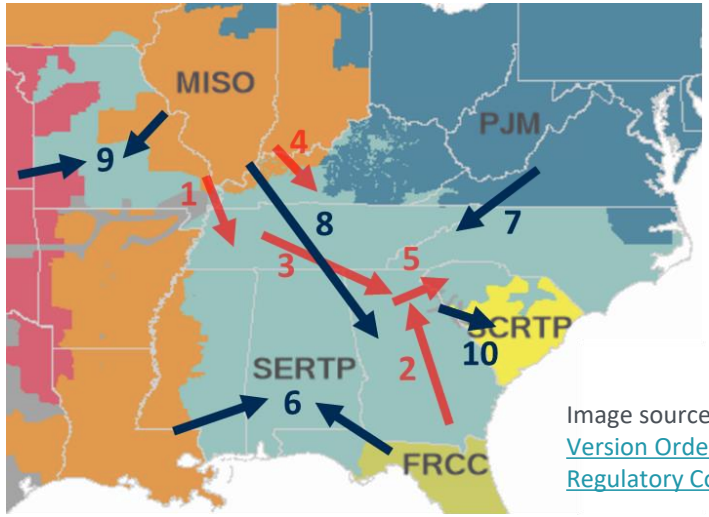


Image source: Regions Map Printable Version Order No. 1000 | Federal Energy Regulatory Commission (ferc.gov)

Major Regional Upgrades Identified for 10 GW Request

Stakeholders in 2024 requested SERTP to study a 10 GW transfer from MISO North to SOCO that resulted in SERTP identifying $4.6 billion of regional upgrades between TVA, Duke, and SOCO.

- Request triggered 139 violations and identified the need for seven new 500 kV lines and 40 other upgrades

SERTP selected three 500 kV lines for their analysis of more efficient and more cost-effective regional upgrades but identified no avoided local upgrade costs and considered no other cost savings or benefits.

10 GW Economic Request Reliability Violations

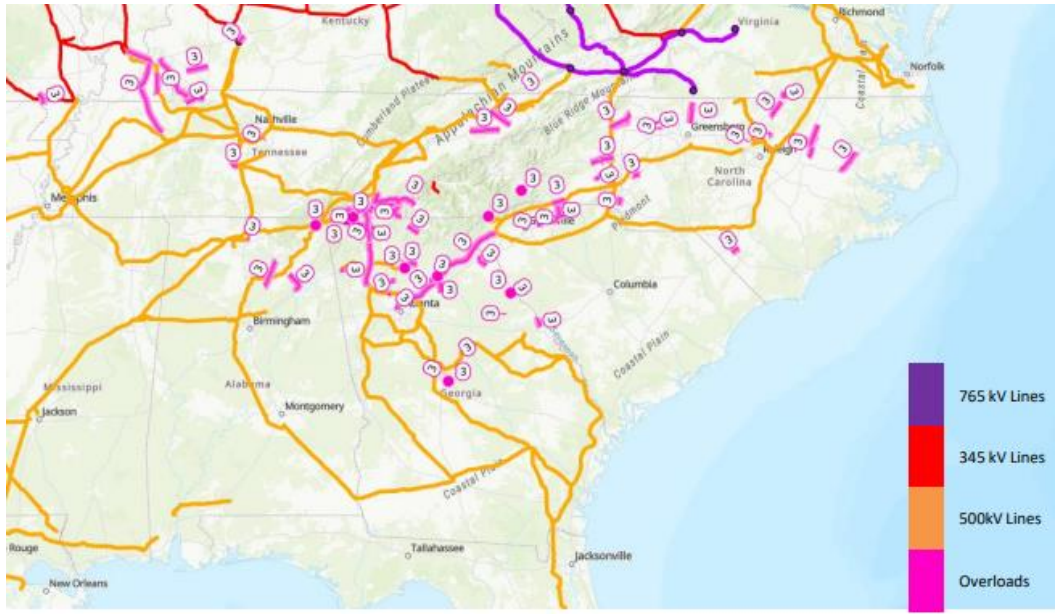


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 25.

Regional Projects for Additional Analysis

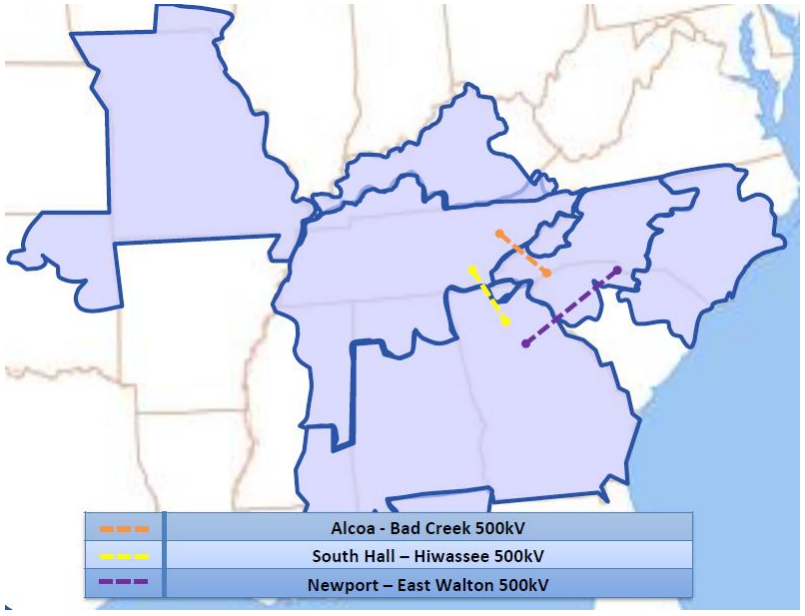


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 49.

SERTP Has Not Studied Regional Public Policy Needs

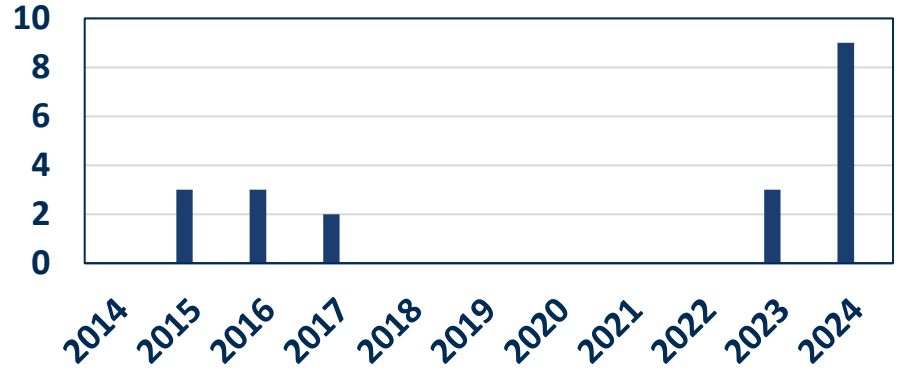
Stakeholders may propose transmission needs driven by Public Policy Requirements (PPRs) for SERTP to assess if the requests meet the following criteria:

1. Is the PPR an enacted local, state, or federal law(s) and/or regulation(s)?
2. Does the PPR drive a transmission need(s)?
3. Is the transmission need already addressed or otherwise being evaluated in the then-current planning cycle?

SERTP has never evaluated a regional transmission needs for a PPR

- The narrow scope of a PPR excludes Sponsors' Board commitments and SERTP's reliance on local transmission plans means that state laws can be considered as addressed in Sponsors' local plans
- For example, SERTP responded to a 2024 PPR request to study the North Carolina Carbon Plan by noting that the needs are already being considered in the CTPC local planning process, and so "no additional transmission needs for the proposed PPR have been identified"
- In doing so, SERTP fails to consider the potential for regional capacity to reduce the costs of satisfying policy requirements across the Southeast

SERTP Public Policy Requirements Proposals for Transmission Needs since 2014



Sources: SERTP Archive Documents, Transmission Needs Driven by Public Policy Requirements (2014–2024).

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 Transmission Planning Results in Higher Total Costs

Current SERTP regional planning does not yield the most valuable and cost-effective transmission infrastructure for the following reasons:

- Reactive, reliability-driven planning results in piecemeal, higher-cost transmission solutions
- Failure to evaluate full range of plausible futures that explicitly account for long-term uncertainties results in higher-cost outcomes when the future deviates from base case planning assumptions
- Lack of consideration of multiple benefits of transmission does not result in the selection of the highest-value projects that reduce system-wide costs; currently only reliability and losses considered

Maximizing the value of regional upgrades may require SERTP Sponsors to modify their approaches to resource planning and market transactions to efficiently utilize the existing and planned regional transmission capacity.

FERC Order No. 1920 presents a critical opportunity for SERTP to enhance coordination, optimize investments, and ensure cost-effective solutions that benefit both utilities and customers.

III. Recommendations to Enhance SERTP Regional Planning



Exhibit AP-3

Framework for Improved SERTP Regional Planning Process

Experience across the electric power industry over the past 10–20 years provides 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: anticipated generation mix and load levels 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 accounts for all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging weather 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

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

Recommendations to Enhance SERTP Regional Planning

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

I. Improve Existing Planning Process

1. **Increase transparency** of study assumptions, approach, and results
2. **Engage state commissions and energy agencies** to participate in process and ensure results reduce costs and address state policies
3. Expand solutions studied to reflect **least-cost transmission "loading order"** that maximizes existing grid, upgrades existing lines, and builds new lines where necessary

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 **region-wide production cost model**
6. Develop guidelines to account for **comprehensive set of cost savings and 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**

1. Increase SERTP Planning Transparency

SERTP process lacks transparency, restricting the ability of stakeholders and state utility commission to review study assumptions, approach, and results and provide feedback to SERTP on ways to improve regional planning.

- Modeling approaches and costs of Sponsors' local upgrade projects, the only regional benefit considered by SERTP, are opaque with CEII clearance required to access information that is not restricted in other planning regions
- Even with CEII access, stakeholders lack cost information and only receive raw power flow cases, not study details and results

Greater Access to Input Assumptions

- In 2024, SERTP identified changes in the resource mix by type and utility
- Provide more clarity and consistency in resource updates across utilities
- More granular information on load forecasts between BAAs, including coincident peak analysis

More Information on Study Results

- Provide more detailed results, including:
  1. Limiting element that triggers violation
  2. Alternative solutions studied
  3. Basis for selecting solution
- Include individual solution estimated costs in the preliminary and final regional transmission plan

Expand Results of Regional Project Analyses

- Detail the selection process of each regional project that is selected for analysis: what motivated the selection of the line(s), how many years of the 10-year study are their benefits analyzed for, etc.

Longer Time Windows for Stakeholder Interaction

- Lengthen window that stakeholders have to submit comments on criteria and method used in planning process beyond only 10 business days
- Ensure documents are posted more than 10 days prior to meetings to give ample time to review

2. Engage State Commissions and Energy Agencies

State agencies and commissions should be actively engaged in the SERTP process to incorporate the perspectives and priorities of regulators and energy agencies into regional transmission planning.

By having insight into regional planning, regulators can ensure that customers are paying for an efficient power system that meets state policy goals and provides reliable electric service.

SPP Regional State Committee (RSC)

- Comprised of state commissioners from 12 states within SPP
- **RSC maintains Federal Power Act 205 rights** to file proposals with FERC to modify rules and tariffs
- Decision making is shared between SPP Board and RSC; RSC has primary responsibility for resource adequacy and cost allocation

Organization of PJM State Inc. (OPSI)

- Collaborative body representing 14 regulatory agencies within PJM
- Facilitates communication and coordination among members, **allowing states to collectively address** PJM operations and market rules
- Ensures that **state interests and policies are considered** in regional decision-making processes

NorthernGrid Enrolled Parties and States Committee (EPSC)

- Participate in development of regional study scope and provide comments on draft regional plans
- Enables **state agencies to participate actively in transmission planning** and **ensures that state-specific concerns and objectives are addressed** within the regional planning framework

Other state organizations participating in regional planning include Organization of MISO States (OMS) and New England States Committee (NESCOE). The California Public Utilities Commission and New York Public Service Commission play an active role in regional planning within their respective single-state RTOs.

3. Expand Solutions to Reflect a Least-Cost Loading Order

SERTP should expand the solutions considered in its studies to include grid-enhancing technologies (GETs), advanced transmission technologies (ATTs), and remedial action schemes (RAS) that maximize the utilization of the existing grid to accommodate new load and generation in the near-term.

By studying potential solution alternatives, SERTP can "stack" solutions by estimated cost and schedule to identify the most beneficial solutions to providing a reliable and efficient grid.

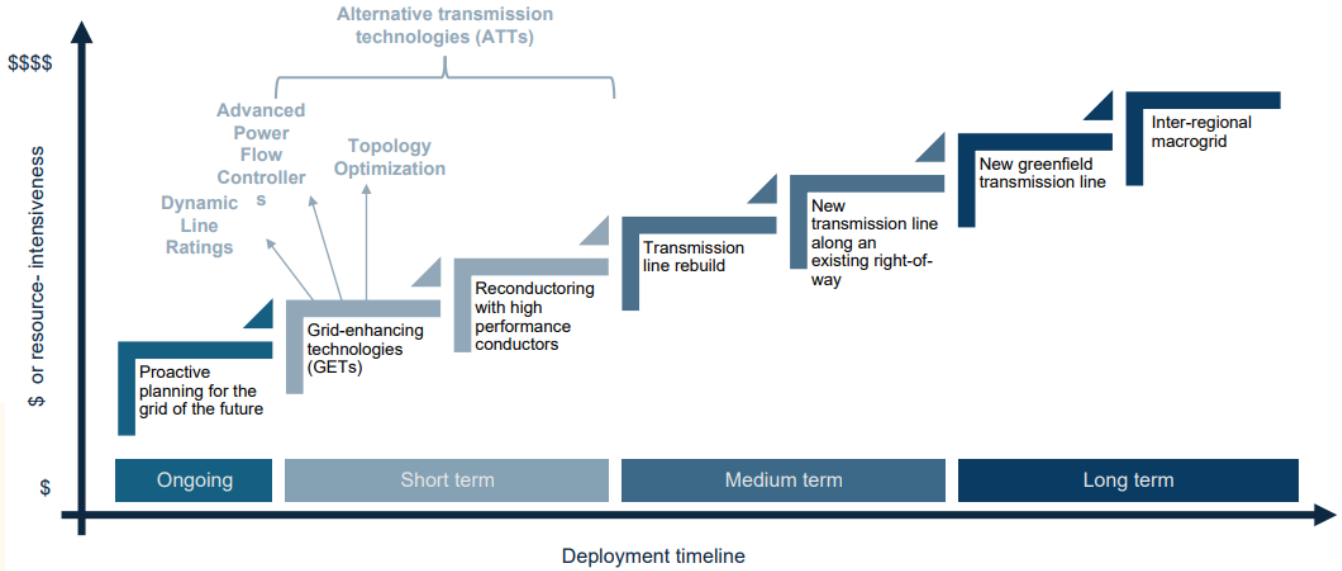
Southeast examples:

- Georgia Power relied on operating guidelines and ATTs in its most recent IRP to resolve reliability-driven system needs
- Duke's MVST will consider GETs, advanced conductors, RAS, and battery storage as well as greenfield transmission and ROW optimization

Further Examples:

- CAISO use of RAS to create 15 GW of headroom
- Priority order required by the German "NOVA Principle"
- MA CETWG Report: "Loading Order" recommendations

Proposed Transmission Solution Loading Order



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

4. Develop Multiple Future Scenarios Based on IRPs

Scenario-based planning is a process first developed in the 1940s and 1950s as a tool for **integrating uncertainties into long-term strategic planning**.

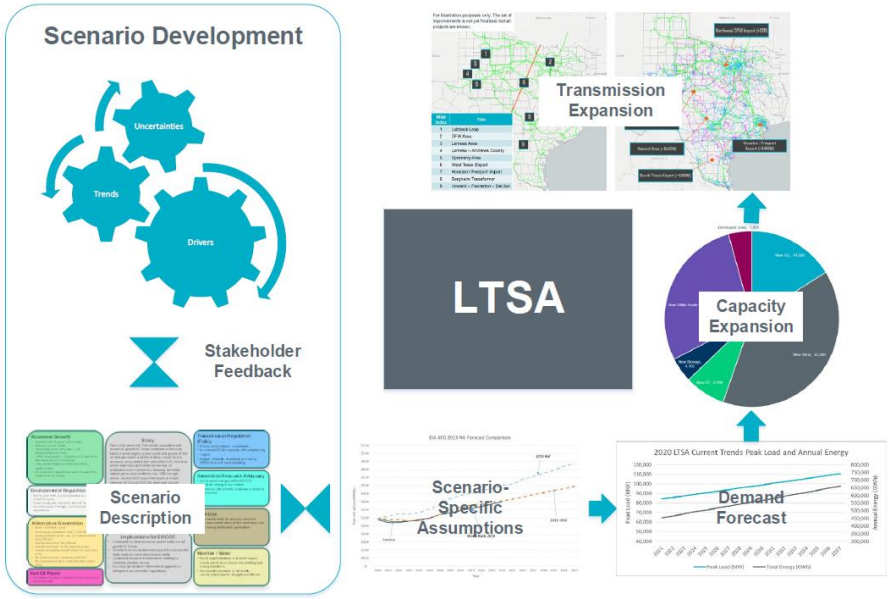
- Used by Shell since the 1970s for long-term planning under large uncertainties
- Assists planners to think in advance about the many ways the future may unfold and how to respond effectively and flexibly as the future becomes reality
- Scenario = one fully-defined, plausible view of what the future may look like

Examples of scenario-based planning approaches used in regional transmission planning include:

- ERCOT's Long-Term System Assessment Process (LTSA)
- MISO's Long Range Transmission Planning (LTRP)
- SPP's recent Integrated Transmission Plan (ITP)

SERTP should leverage the range of future outlooks for demand and generation resources already completed by Sponsor utilities in their IRP studies, similar to Duke's use of the Carolinas Resource Plan to study three scenarios in the MVST process.

ERCOT LTSA Process



5 & 6. Study Comprehensive Set of Cost Savings and Benefits

SERTP can take advantage of the best practices developed across the industry over the past 20 years to estimate transmission benefits.

- Analytical approaches for quantifying transmission benefits have been documented in a report submitted to FERC cited in Order 1920
- Planners have implemented these analyses to justify major investments in regional transmission

Critical for SERTP to develop a detailed nodal production cost model of its region to accurately capture congestion to identify needs and estimate cost savings of transmission solutions.

New approaches continue to be developed to accurately 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

Transmission Cost Savings and Benefits Quantified by Planners

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

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

5 & 6. Planners Approved Upgrades based on Cost Savings

SERTP should review industry experience analyzing a comprehensive set of cost savings and other benefits and develop planning guidelines for estimating transmission benefits in future regional studies

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 provide capacity and energy 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 DPV2 Analysis

Quantified

1. **Production cost savings*** and reduced energy prices from societal and customer perspective
2. Mitigation of market power
3. Insurance value for high-impact low-probability events
4. Capacity benefits due to reduced gen 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 AC Upgrades Analysis

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

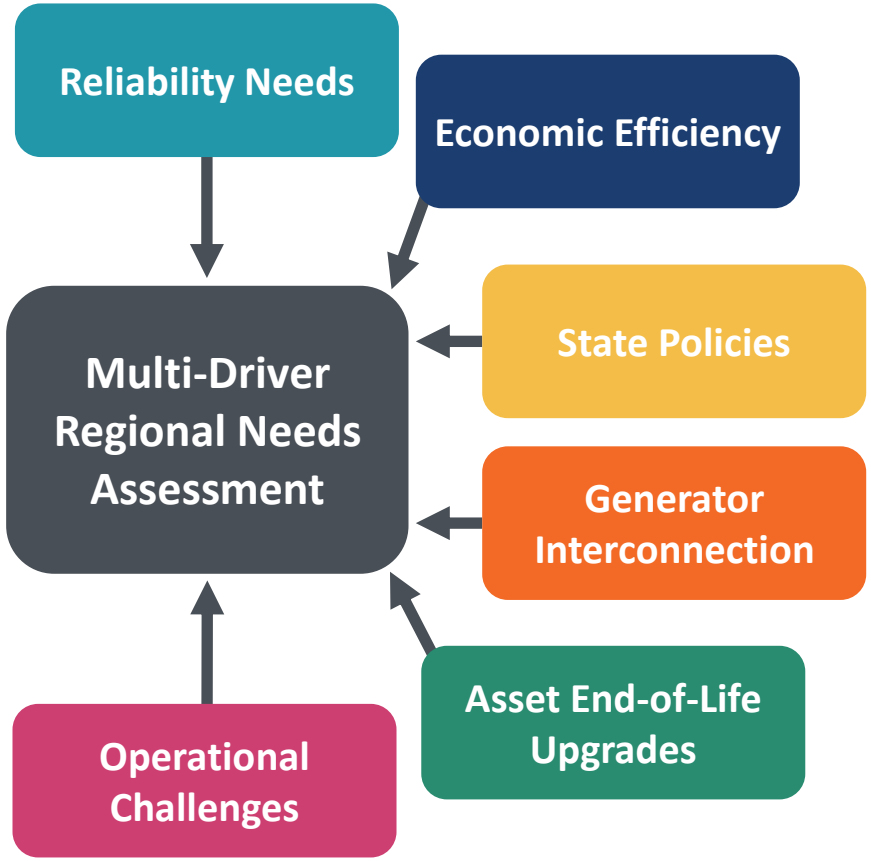
7. Multi-Driver Needs Assessment to Identify Solutions

Implementing a multi-driver approach to identifying regional transmission needs will allow regional transmission planners to identify overlapping concerns and develop cost-effective, right-sized solutions that can provide a broad range of benefits.

- Regional transmission can provide multiple benefits, but regional planners often focus solely on identifying the least-cost solutions for single drivers, e.g., reliability, economic efficiency, generator interconnection, or public policy needs, through a siloed process
- Siloed regional planning misses the broader benefits of regional projects that address multiple needs simultaneously, leading to higher overall electricity costs

MISO's LTRP process includes identifying reliability, economic, and policy needs based on several long-term future scenarios.

SPP completes a five-part needs assessment that reviews (1) economic, (2) reliability, (3) public policy, (4) persistent operational, and (5) winter weather needs.



8. Estimate Benefits & Costs over Entire Asset Life

SERTP should evaluate candidate solutions for an expanded set of cost savings and other benefits based on the guidelines it develops with stakeholders over **the full useful life of the solutions**.

For example, **we estimate the potential cost savings of 1 GW of regional transmission** between BAAs within the SERTP region over a 50-year life of a new transmission asset for three benefit metrics.

Production Cost Savings

Regional transmission could provide **$2.8 billion in fuel and congestion cost savings** by increasing transfer capability between major utilities by 1 GW over 50 years.

Transmission BAA Pair	50-year NPV	
	$0/MWh Hurdle	$8/MWh Hurdle
	$ Millions	*$ Millions*
TVA and DUKE	$1,261	$994
SOCO and TVA	$1,244	$963
SOCO and DUKE	$1,138	$871

Load Diversity Savings

By increasing transfer capability for sharing resources between BAAs that take advantage of temporal differences of peak load, SERTP Sponsors could save on avoided generation capacity costs.

Using historical differences in independent system peaks, regional transmission could **reduce costs of achieving resource adequacy requirements by $1.26 billion** by increasing transmission between each of the neighboring SERTP BAAs by 1 GW.

Resiliency Benefits

With additional interregional capability to access generation during Winter Storm Elliot, 1 GW of regional transmission capacity to support customers across the Southeast could have avoided 10 GWh of total load shed.

At a VOLL of $10,000/MWh, **1 GW of regional transmission would avoid $668 million of customer costs due to unserved load,** assuming a similar event occurred every 5 years.

9. Develop Cost Allocation for Approved Portfolios

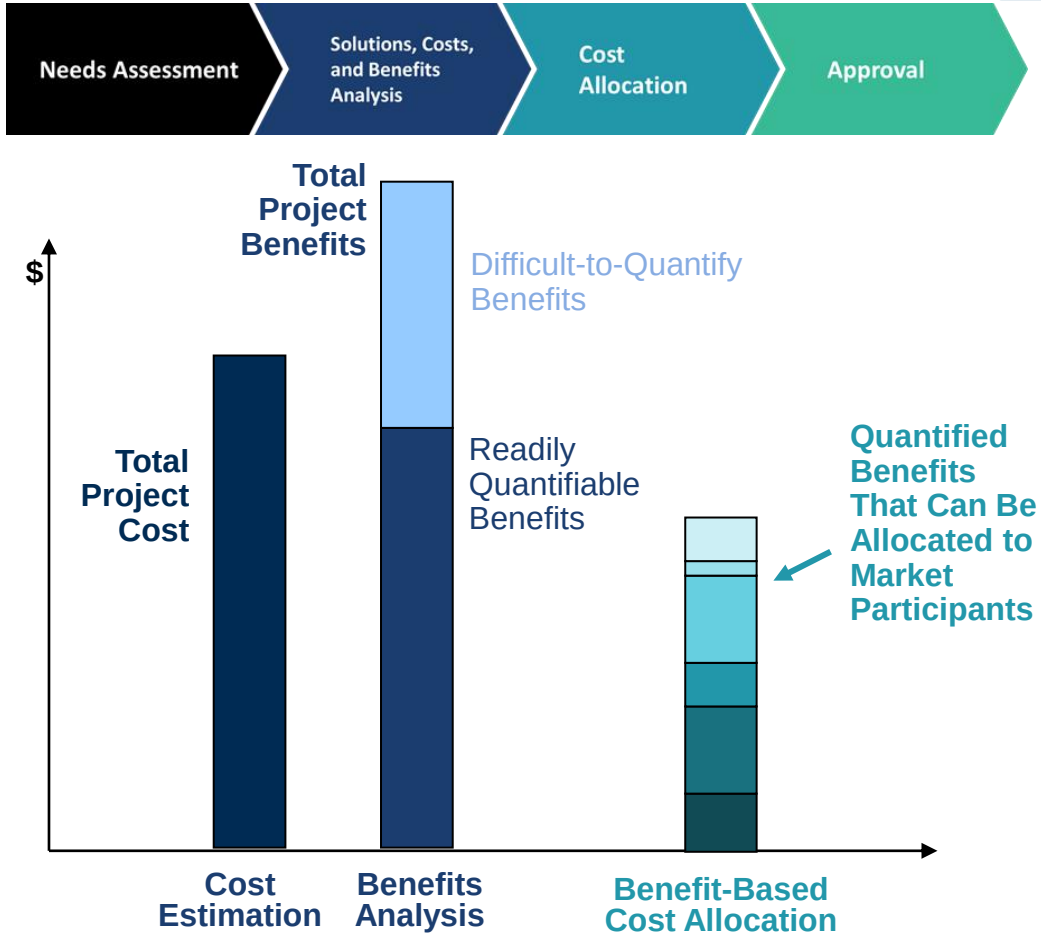
Important for SERTP to develop a regional cost allocation approach that ensures regional customer transmission costs are roughly commensurate with their benefits

To ensure beneficial projects are approved and costs are fairly allocated, recommend a 2-step approach:

1. SERTP determines whether projects are beneficial overall based on a broad set of benefits over the life of the asset
2. Evaluate how to allocate the costs of a portfolio of projects based on their joint distribution of benefits

This approach will tend to reduce issues related to cost allocation, as a broad set of benefits quantified for a portfolio of projects tends to be more stable over time and be distributed more uniformly.

SERTP should weigh the tradeoffs of an overly formulaic approach to cost allocation versus a simpler load-ratio-share approach for Sponsors with demonstrated benefits.



IV. Why the Southeast Needs to Modernize Its Regional Planning Process Now to Reduce Costs and Increase Reliability



Regional Upgrades Are Providing Benefits Across U.S.

Every region across the U.S. other than the Southeast has taken proactive steps to build out its regional grid in order to lower electricity costs, improve reliability, and support economic growth.

The following regional projects pursued in the past few years represents $117 billion of investments:

- MISO LRTP Tranche 1 and Tranche 2.1 Portfolios: $33 billion (see following slides)
- ERCOT 2025 Upgrades to Serve Load Growth: $32 billion
- Southwest Power Pool 2024 Integrated Transmission Planning (ITP) Portfolio: $11 billion
- California ISO 2022/23 and 2023/24 Policy Projects: $10 billion
- PacifiCorp Energy Gateway and Boardman-to-Hemingway Projects: $8 billion
- Champlain Hudson Power Express and NECEC to Access Canadian Hydro: $8 billion
- PJM 2024 RTEP Data Center-Driven Regional Upgrades: $6 billion

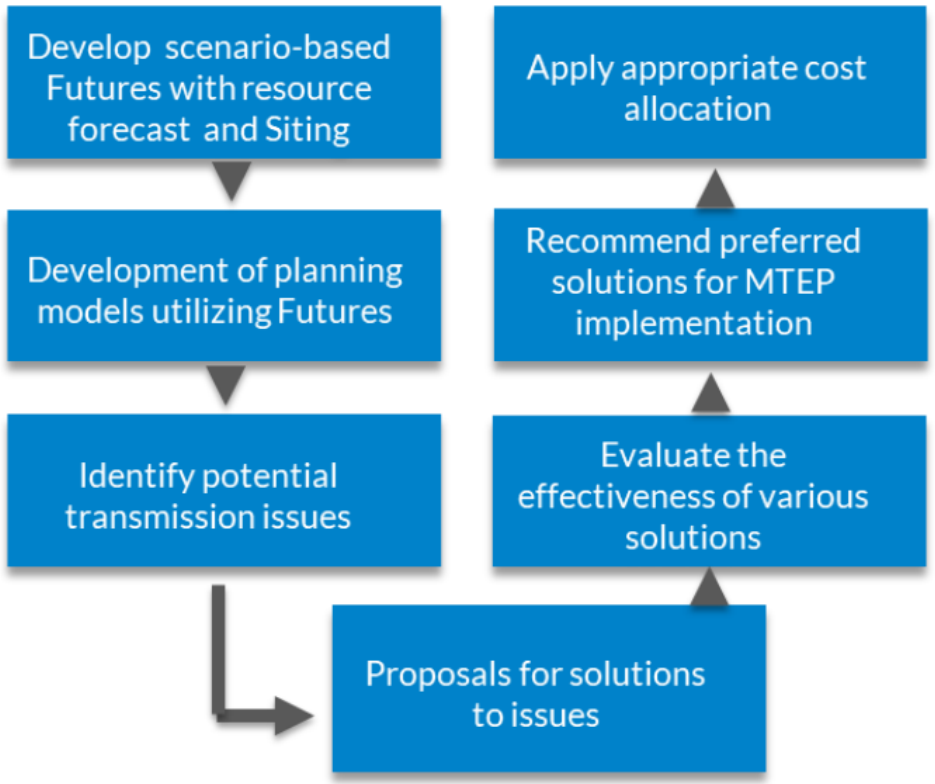
Similar system needs that led transmission planners across the country to embrace proactive regional transmission planning also apply to the Southeast and SERTP as demonstrated by national studies.

MISO and the Carolinas Transmission Planning Collaborative (CTPC) provide clear examples of proactive transmission planning approaches that SERTP should consider for enhancing its regional planning process.

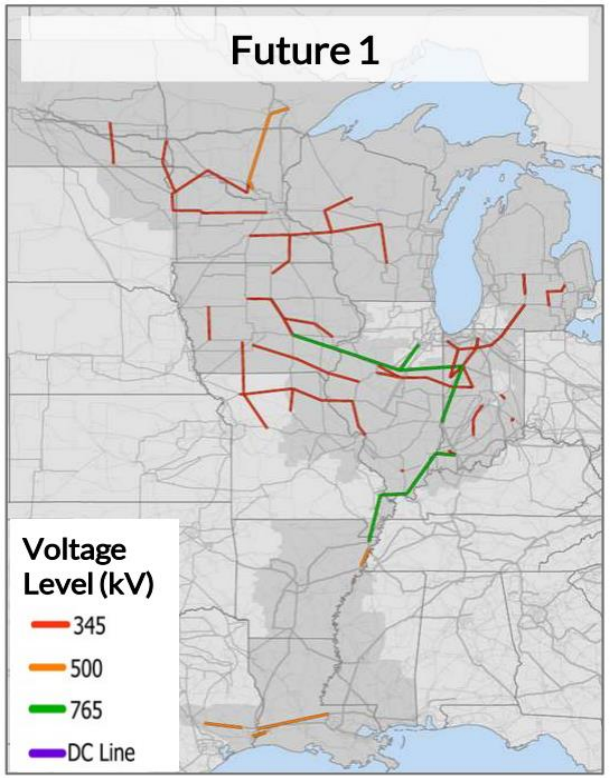
MISO Long Range Transmission Planning Process

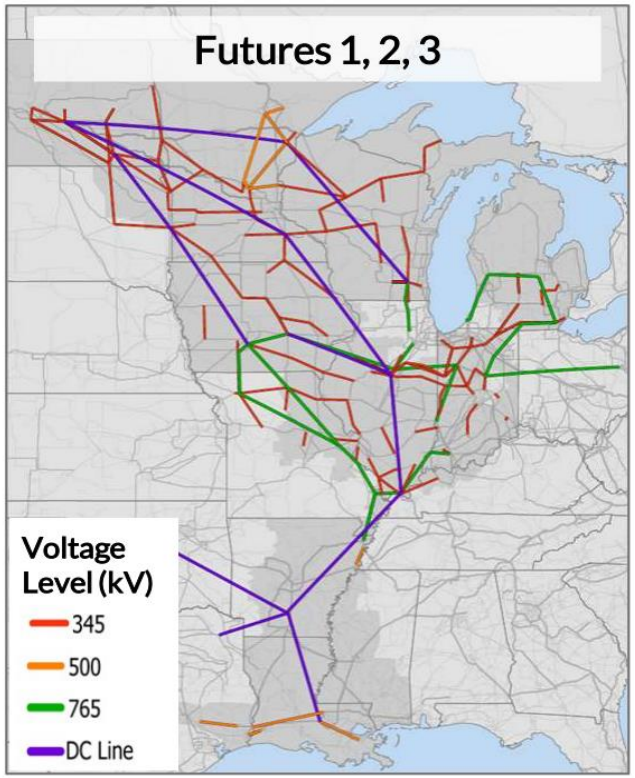
MISO's LRTP Tranche 1 and Tranche 2.1 evaluated 20-year reliability, economic, and policy needs for three plausible "Futures" scenarios that accounted for uncertainty in load growth and generation.

MISO' LRTP Process



MISO's Identified Long-Term Transmission Needs





Source: MISO LRTP Roadmap March 2021

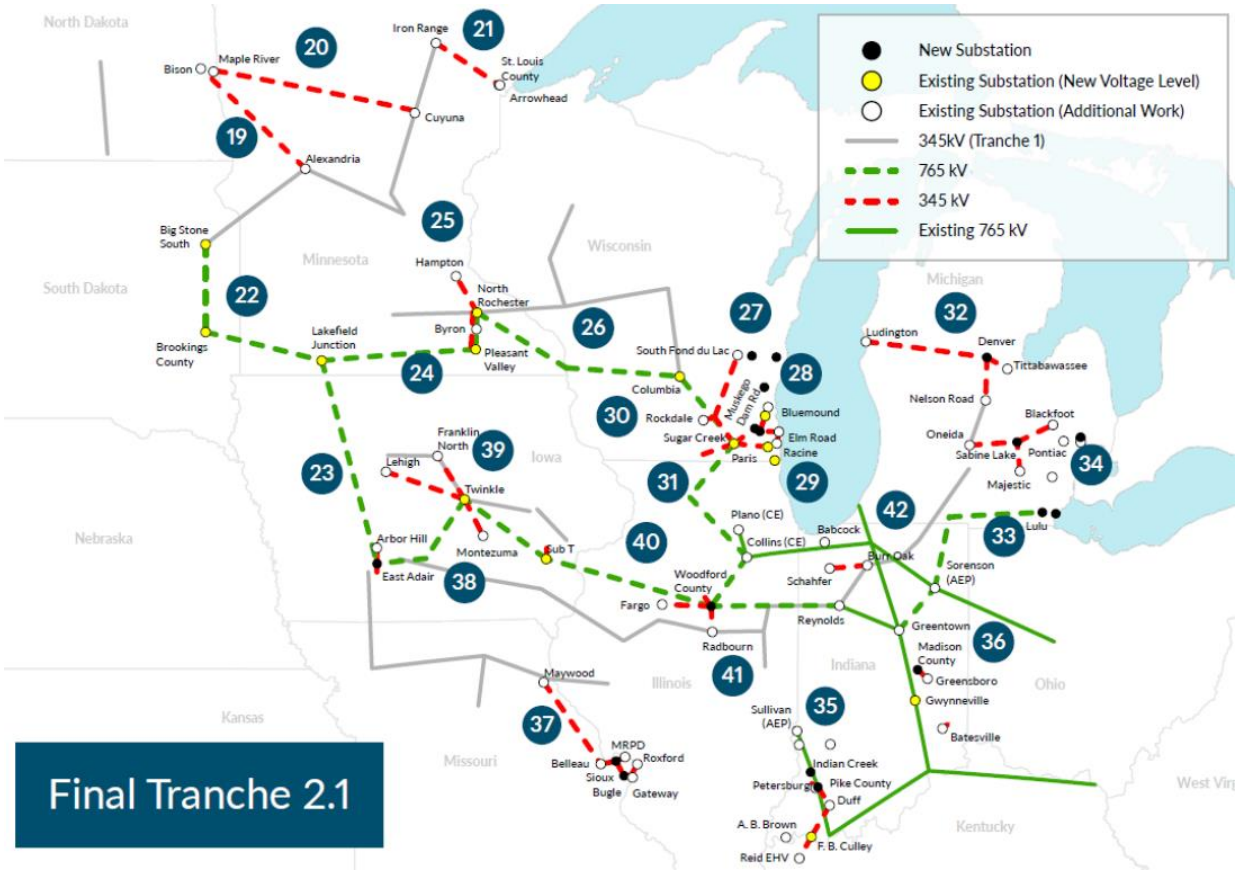
MISO Long-Range Transmission Planning Results

MISO completed the first two tranches of its LRTP multi-value planning process, which resulted in $33 billion of regional transmission investment to modernize its grid.

MISO LRTP RESULTS

- Tranche 1 results:
  - $10 billion portfolio of new 345 kV projects
  - Supports interconnection of 53 GW of renewable resources
  - Reduces system costs by $37–70 billion
- Tranche 2.1 results:
  - $22 billion portfolio of new 345 kV and 765 kV projects and substations
  - Reduces system costs by $34–62 billion
- Portfolios of LRTP projects designed to benefit each zone within MISO's Midwest Subregion with costs allocated on a postage-stamp (per-MWh) basis to customers in MISO Midwest

MISO LRTP Tranche 1 and Tranche 2.1 Projects



Source: https://www.misoenergy.org/planning/long-range-transmission-planning/

CTPC/Duke Multi-Value Strategic Transmission (MVST) Study

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 added to its local planning process a **proactive, scenario-based, multi-driver process to identify Multi-Value Strategic Transmission (MVST) projects;** implementing its first MVST study in 2024–2025.

Key Aspects of CTPC Multi-Value Strategic Transmission Process



IRP-based Scenarios

Identify reliability and economic needs for future scenarios based on Duke's projected load and IRP-developed generation portfolios

Alternative Solutions

Consider GETs, advanced conductors, Remedial Action Schemes (RAS), and storage as potential solutions as well as existing lines upgrades and greenfield transmission

Portfolio Evaluation

Evaluate a portfolio of transmission solutions over the life of the assets to resolve identified needs

Benefits Analysis

Quantify (1) avoided capacity costs, (2&3) capacity cost and energy cost savings from reduced losses, (4) congestion and fuel cost savings, (5) avoided customer outages, and (6) avoided transmission costs

Case Study: Assessing Benefits of SERTP Regional Projects

To demonstrate the value of Southeast regional transmission, we performed a high-level analysis of three 500 kV upgrades SERTP identified in its 2024 regional planning process (see map).

The analysis evaluated the potential cost savings and other benefits of the regional projects based on an expanded set of benefits utilizing recent historical market data:

- **Production cost savings** based on historical 2015–2023 system lambdas reported by SERTP Sponsors as a proxy
- **Load diversity benefits** based on historical 2011–2023 load shapes, accounting for capacity cost savings from imports
- **Resilience benefits** during extreme weather conditions, such as Winter Storm Elliott

Regional Projects Evaluated in 2024 SERTP Regional Plan

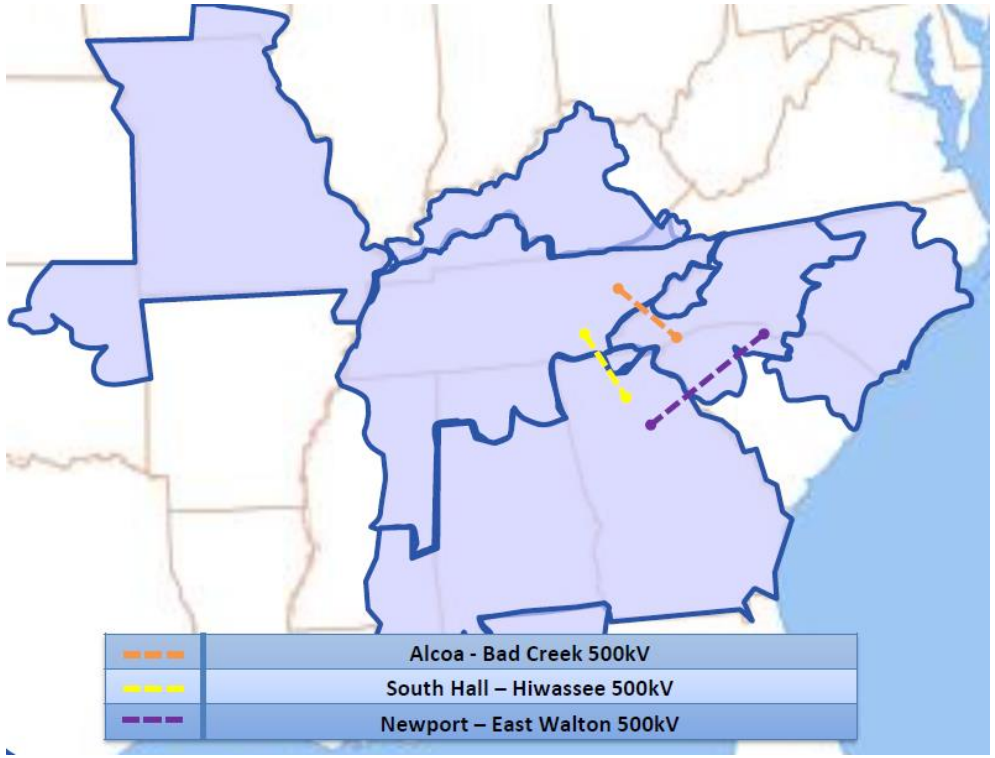


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 49.

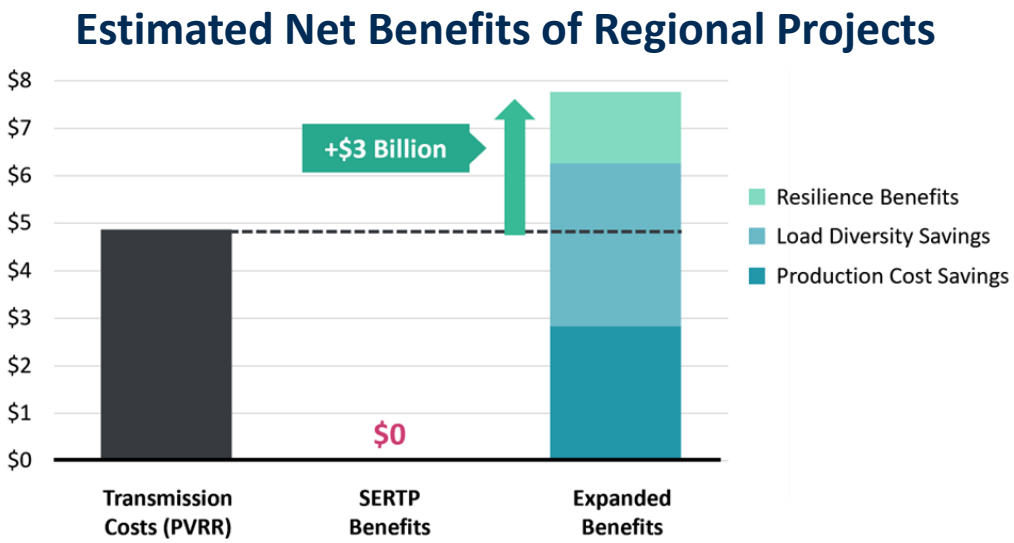
Expanded Scope of Cost Savings Identifies Cost-Effective Upgrades

Using an expanding set of benefits, we estimated $8 billion of cost savings and other benefits for these proposed regional lines, resulting in $3 billion of net benefits for customers in the Southeast over the life of the assets.

- Production cost savings: $2.8 billion (range: $2.0–3.6 billion)
- Load diversity cost savings: $3.3 billion (range: $0.9–6.0 billion)
- Resilience benefits: $1.6 billion (range: $0.7–2.3 billion)
- *Note: A more detailed study is likely to identify additional benefits not quantified in this high-level analysis, including avoided reliability and interconnection upgrades, greater production cost savings with increased solar/wind, and reduced generation costs*

Regional transmission can reduce system costs when a broader scope of cost savings and other benefits are analyzed

By contrast, SERTP's very narrow view of benefits based solely on avoided local transmission costs identified **no cost savings**.



Note: Detailed results included in the appendix slides. Load diversity savings were capped at 1 GW of potential value, as we assumed the new lines would be limited to about 1 GW of capacity.

Order 1920 Provides Southeast Opportunity in 2025 to Enhance Its Regional Transmission Planning Process

- **Southeast is the only major U.S. region that has not pursued significant regional transmission projects over the past decade**
- **Every year without a proactive regional transmission planning process in the Southeast results in higher electricity bills, increased blackout risks, and lost business investment over the long term due to insufficient grid infrastructure**
- **FERC issued Order No. 1920 last year that requires SERTP to implement a proactive, long-term, multi-value regional planning process, presenting a pivotal opportunity for the Southeast to align its regional transmission planning with industry best practices developed over the past 10–20 years**
- **The Southeast should embrace this opportunity in 2025 to modernize SERTP's regional transmission planning to build a stronger, more efficient grid that supports economic growth, energy affordability, and long-term resilience**

Appendix: Case Study Detailed Analysis

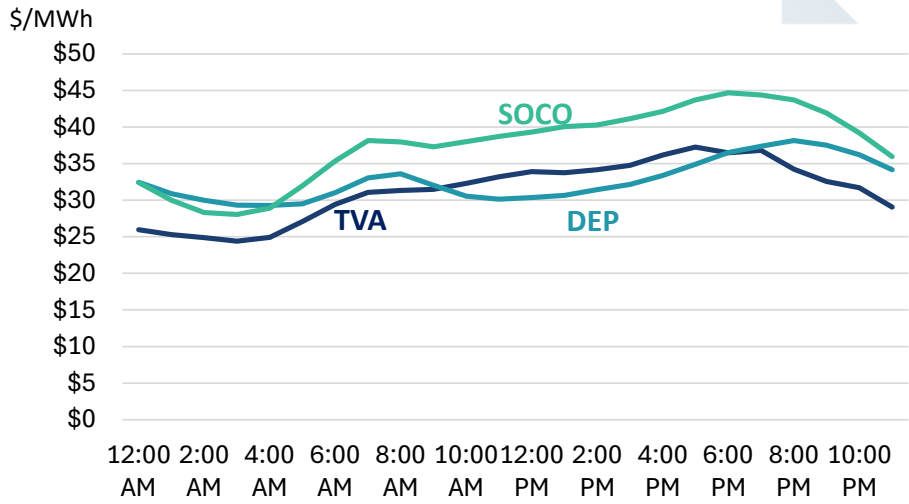
Privileged and confidential. Prepared at the request of counsel.

Estimated Production Cost Savings

Using historical system lambdas, we estimate the potential value of 1 GW of transfer capability for pairs of our case study balancing authorities

- Methodology for Estimating Production Cost Savings:
  - System lambdas represent an approximation of marginal unit cost in an hour and are directly reported by each utility to FERC
  - We assume the new transmission will optimize flows by sending power from the BA with a lower price to the BA with a higher price every hour when the price separation exceeds a specific "hurdle" (representing trading costs like wheeling charges and other frictions)[1]
  - Resulting flow and price separation estimate value of new transmission upgrades
- Production Cost Savings Results:
  - With a trading hurdle of $8/MWh, the regional upgrades provide $2.8 billion in production cost savings
  - Average price separation between BAs is $8 - $10/MWh, but there is significant value in periods of high price separation

2019-2023 Average Marginal Cost of Energy



Estimated 2019 – 2023 Value of 1 GW of New Transmission

Transmission BAA Pair	Average Annual 2019-2023 Value			50 Year NPV of 1,000 MW (at 7% Discount Rate)		
	$0/MWh Hurdle	$8/MWh Hurdle	$15/MWh Hurdle	$0/MWh Hurdle	$8/MWh Hurdle	$15/MWh Hurdle
	$ Millions	*$ Millions*	*$ Millions*	*$ Millions*	*$ Millions*	*$ Millions*
TVA and DUKE	$91	$72	$55	$1,261	$994	$758
SOCO and TVA	$90	$70	$49	$1,244	$963	$671
SOCO and DUKE	$82	$63	$43	$1,138	$871	$596
			Total Savings	$3,643	$2,828	$2,025

[1] The selection of $8/MWh and $15/MWh hurdle rates mimics the low-coordination and high-coordination scenarios in the Southeast from Kahrl, Fredrich, et al., *Solar and Storage Integration in the Southeastern United States: Economics, Reliability, and Operations.* Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, 2024.

Load Diversity Savings Value

Interregional transmission unlocks a planning benefit to utilities that we call 'load diversity savings' which is: The value of capacity avoided by one region by relying on capacity in another region that is enabled by transmission

- Utilities plan their generation fleet to meet their own annual peak load, not considering that a balancing authority near them may have spare capacity at the same time due to regional diversity in load shapes
  - *Duke for example may experience peak load at 6pm EST while TVA may peak at 7pm EST, or in different months entirely*
- **This savings value is calculated by determining how much lower the combined coincident peak of two balancing authorities is compared to their own independent annual peak loads**
  - By planning for one combined coincident peak, you can avoid capacity costs in one or both balancing authorities
  - This benefit **is only reliable if you have expanded interregional transmission** that allows you to rely on capacity from another balancing authority during peak load periods
- **The next three slides walk through how we estimate this metric historically**

Load Diversity Benefits of Regional Upgrades

Potential capacity savings exist from the diversity of peak load in the Southeast

- **Potential capacity savings**: Comparison of two BAAs **independent peaks** and their BAA peak under the pair's **joint coincident peak**
- **Existing transmission capacity:** EIA historic 95th percentile and maximum transmission flows between the BAAs
- Potential savings vs. EIA 95th percentile historic (2015-2023) transfer limits

At an avoided capital cost of $833/kW, the potential capital cost savings using the sum of the average potential savings **would be $1,256 million**

- *Based on 2025 AEO Tennessee Gas-CT capital cost*
- *Cost savings are higher once you include operating cost of the gas plant and cost of capital*
- *Would be even higher for avoided storage*

Potential Load Diversity Benefits of Transmission Expansion (MW)

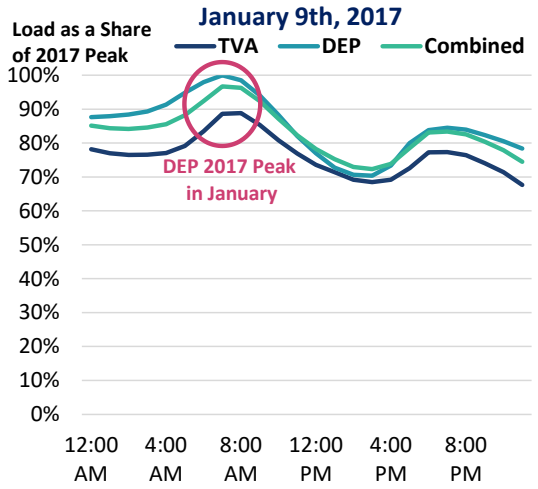
BAA Pair		Potential Peak Savings from TX		EIA Historic Transfer Limits	Potential Savings - EIA Limits	
BAA Pair	BAA	2011-2023 Average Potential Savings	2011-2023 Maximum Potential Savings	EIA Implied Transfer Limit	Average Potential Savings - EIA Transfer Limit	Maximum Potential Savings - EIA Transfer Limit
TVA <> AECI	TVA	28	205	325		
	AECI	461	1,459	38	**423**	**1,421**
TVA <> SOCO	TVA	446	2,170	1,546		**624**
	SOCO	127	670	1,802		
TVA <> DEC	TVA	221	1,133	154	**67**	**979**
	DEC	658	1,597	323	**335**	**1,274**
TVA <> DEP	TVA	118	906	68	**50**	**838**
	DEP	737	2,380	104	**633**	**2,276**
DEP <> SOCO	DEP	604	1,932	1,501		**431**
	SOCO	106	934	1,692		
DEC <> SOCO	DEC	287	885	502		**383**
	SOCO	199	1,515	1,163		**352**

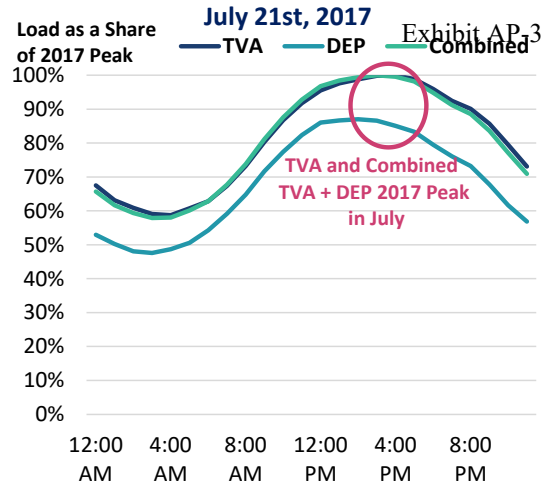
Load Diversity Savings Value

As an example, DEP peaks independently in January 2017 while TVA is 3.4 GW below its own 2017 peak that it planned its system to meet

TVA and DEP's load diversity savings calculation is shown on the right

- The independent gross peak is each BAs annual peak on their own
- The coincident peak is each BAs load during the joint TVA + DEP peak during the year
- The potential load diversity savings is the difference between a BA's gross peak and load during the coincident peak
- **This is then compared in our summary table in the previous slide to the existing transfer capacity** to see if this diversity value can be captured via existing transmission already





Load Diversity Savings Calculation Example for TVA and DEP

	Tennessee Valley Authority			Duke Energy Progress LLC		
Year	Independent Gross Peak	Peak During TVA + DEP Coincident Peak	Potential Load Diversity Savings from TX	Independent Gross Peak	Peak During TVA + DEP Coincident Peak	Potential Load Diversity Savings from TX
	MW	*MW*	*MW*	*MW*	*MW*	*MW*
2011	36,765	36,627	138	16,244	15,861	383
2012	36,696	36,696	0	16,095	15,989	106
2013	33,897	33,897	0	15,278	14,649	630
2014	39,355	39,355	0	17,342	17,170	172
2015	38,646	38,646	0	18,994	17,713	1,281
2016	35,192	35,192	0	16,224	16,224	0
2017	35,281	35,235	46	17,731	15,351	2,380
2018	38,361	37,454	906	18,933	17,969	964
2019	34,891	34,891	0	16,676	15,533	1,143
2020	34,139	34,111	27	16,144	16,144	0
2021	35,883	35,553	329	15,916	15,666	250
2022	39,442	39,355	86	17,181	15,538	1,643
2023	37,578	37,578	0	15,825	15,202	622
Average Peak Saving			**118**			**737**
Maximum Peak Saving			**906**			**2,380**

Load Diversity Savings Value

Potential load diversity savings between our four case-study examples from 2011 – 2023 average over $900 million, mostly between TVA and Duke

- Average avoided capacity cost denotes the 2011 – 2023 average annual load diversity savings vs. the maximum which denotes the highest year of possible savings
- Maximum avoided capacity savings are nearly $6 billion across the four BAAs for up to 2.3 GW of transmission
- These savings are likely to increase in the future as it does not include projected load growth

BAA Combinations for 2011 – 2023 Potential Load Diversity Savings

Metric			TVA - DEP		TVA - DEC		TVA - SOCO		SOCO - DEP		SOCO - DEC	
Metric	Unit	Col.	TVA	DEP	TVA	DEC	TVA	SOCO	SOCO	DEP	SOCO	DEP
Average Load Diversity Savings	MW	[1]	118	737	221	658	446	127	106	604	199	287
Maximum Load Diversity Savings	MW	[2]	906	2,380	1,133	1,597	2,170	670	934	1,932	1,515	885
EIA Implied Import Capacity	MW	[3]	68	104	154	323	1,546	1,802	1,692	1,501	1,163	502
Avg. Savings - Import Capacity	MW	[4]	50	633	67	335	-	-	-	-	-	-
Max. Savings - Import Capacity	MW	[5]	838	2,276	979	1,274	624	-	-	431	352	383
Avg. Avoided Capacity Cost	$ Millions	[6]	$42	$527	$56	$279	-	-	-	-	-	-
Max. Avoided Capacity Cost	$ Millions	[7]	$698	$1,896	$816	$1,061	$520	-	-	$359	$293	$319

$904 million savings

$5,962 million savings

Notes: [1] & [2] include 2011 – 2023 hourly load data from EIA calculated for each BAA pair. [3] is the 95th percentile of historic 2015 – 2023 EIA transfers between BAAs. [4] is [1] – [3] when [1] > [3]. [5] is [2] – [3] when [2] > [3]. [6] and [7] multiply [4] and [5] by $833/kW, our assumed cost of peaking capacity from the EIA's 2025 AEO Gas-CT cost for Tennessee.

Resilience Benefits from Transmission

Additional customer savings are unlocked from transmission in the form of resilience to extreme weather events like Winter Storm Elliott by allowing BAs to import power in periods of system stress

TVA, Duke, and LG&E/KU were all forced to order firm load shedding during Winter Storm Elliott

- TVA shed 19,000 MWh; Duke shed a combined 4,936 MWh; and LG&E/KU shed 1,265 MWh

Utilizing regional and interregional transmission to unlock greater access to imports during emergency events can avoid load shed and create significant cost savings resulting from lost load

- Lost load is valued somewhere between $10,000/MWh (in MISO) and $35,000/MWh (in ERCOT)
- Based on outage data from Winter Storm Elliott, 1 GW of additional transmission available to import generation across the region could have avoided between $95 million to $333 million in lost load during the event

If we assume these events happen roughly every five years, regional transmission could provide nearly $668 million to $2.3 billion in resiliency benefits of avoided lost load.

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CERTIFICATE OF SERVICE

I certify that I have served the following parties with the foregoing **Direct Testimony and Exhibits of Alejandro Palomino on Behalf of Southern Renewable Energy Association** by electronic mail, this 2nd day of May, 2025.

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