BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S 2025 INTEGRATED RESOURCE PLAN	))	**DOCKET NO. 56002**
GEORGIA POWER COMPANY'S 2025 APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND SIDE MANAGEMENT PLAN	))))	**DOCKET NO. 56003**

PUBLIC DISCLOSURE

DIRECT TESTIMONY

AND EXHIBITS

OF

MICHAEL S. GOGGIN

On Behalf of the

Georgia Public Service Commission
Public Interest Advocacy Staff

May 5, 2025

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND JOB TITLE.

A. Michael S. Goggin, and I am a Vice President at Grid Strategies, LLC, a consulting firm based in the Washington, DC, area.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit MG-1. This exhibit summarizes my relevant experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am testifying on behalf of the Georgia Public Service Commission ("the Commission") Public Interest Advocacy Staff ("Staff").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION OR OTHER UTILITY REGULATORY BODIES?

A. Yes. I have testified before the Georgia Commission in the last four Georgia Power Integrated Resource Plan ("IRP") cases, which were the 2023 IRP Update and the full IRP filings in 2022, 2019, and 2016. I have also testified before state utility commissions in Arizona, Colorado, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before the Federal Energy Regulatory Commission ("FERC").

Q. CAN YOU PLEASE OUTLINE YOUR TESTIMONY?

A. The primary purpose of my testimony is to address transmission-related aspects of Georgia Power Company's ("Georgia Power's or "the Company's") IRP.

In Section II, I present near-term grid solutions that can save ratepayers money and improve reliability by addressing urgent upgrade needs triggered by load interconnection, local reliability concerns, and generator interconnection. Georgia Power can make greater use of near-term solutions like strategically-sited battery storage, demand response, and grid-enhancing technologies while it implements longer-term upgrades, like the transmission expansion discussed in the next two sections of my testimony.

In Section III, I evaluate the Company's proposed transmission upgrades and the planning process that led to them. The Company's transmission plans include high-voltage solutions that are likely to be cost-effective due to the economies of scale in transmission. Care should be taken in designing some of the lower-voltage solutions to ensure that they include optionality to add a second circuit or to be converted to higher-voltage operation. Some of the lower-voltage solutions may be undersized for the long-term need because the Company's transmission planning process is not sufficiently proactive and does not adequately account for the multiple economic and reliability benefits of transmission. I also recommend that the Company move to a proactive multi-value transmission planning process that other regions have found benefits ratepayers by achieving economies of scale and maximizing net benefits through investment in higher-capacity transmission. This approach proactively plans upgrades to meet expected changes in the generation mix and load growth over the long term, and maximizes the multiple benefits of transmission. I also review best practices for co-optimizing transmission planning with generation planning for truly integrated resource planning.

In Section IV, I highlight how workable regional transmission planning and cost allocation processes can provide economic, reliability, and resilience net benefits for Georgia ratepayers by accessing regional diversity in electricity supply and demand. Expanding transmission ties will access valuable regional diversity as Georgia Power expands its reliance on gas-fired generation that tends to experience higher rates of correlated outages and derates during extreme weather, as well as weather-driven renewable resources. I also identify potential opportunities for expanding ties with neighboring grid operators. These and other potential tie expansions should be further evaluated for net benefits and feasibility.

Finally, I discuss how correlated outages and derates of thermal generation should be directly accounted for in the capacity value accreditations used in the capacity expansion modeling in the IRP, as is done for renewable and storage resources, and not socialized to ratepayers through a higher reserve margin. While this would not change the Company's claimed need for capacity as each MW reduction in thermal generator capacity accreditation would be canceled out by a MW reduction in the planning reserve margin, accurately accrediting resources for their capacity value contributions helps ensure the selection of an economically optimal resource portfolio. Failing to account for thermal resources' reduced capacity value contributions while accounting for how correlations in renewable and storage resource output affect their capacity value results in a suboptimal generation mix.

Q. ARE ANY EXHIBITS ATTACHED TO YOUR TESTIMONY?

A. Yes. In addition to my qualifications, which are in Exhibit MG-1, I have attached Exhibits MG-2 through MG-4, which contain responses to discovery and other materials from past IRP dockets referenced in my testimony.

Q. WHAT IS SHOWN IN EXHIBIT MG-2?

A. Exhibit MG-2 is the Company's response to data request STF-GS-1-1 in the 2023 IRP Update (Docket No. 55378), in which Georgia Power confirms that "The Company did not study Battery Energy Storage Systems ("BESS") as options to reduce, defer, or eliminate the transmission upgrades identified in the 2023 IRP Update to facilitate the delivery of power from the proposed Plant Yates combustion turbines."

Q. WHAT IS SHOWN IN EXHIBIT MG-3?

A. Exhibit MG-3 contains Georgia Power's response to data request STF-GDS-4-7.e. in the 2022 IRP (Docket No. 44160), stating that "Alternative solutions such as energy storage or distributed energy resources have not been considered yet for various reasons." Those reasons include "the magnitude of storage or DER that would be needed makes those options untenable."

Q. WHAT IS SHOWN IN EXHIBIT MG-4?

A. Georgia Power's responses to data requests STF-GS-1-8 and STF-GS-1-9 in the 2023 IRP Update (Docket No. 55378), indicating that the Company does not evaluate demand response as a potential solution to localized transmission needs.

II. THE COMPANY DID NOT ADEQUATELY EVALUATE NEAR-TERM GRID SOLUTIONS LIKE STRATEGICALLY-SITED BATTERIES, DEMAND RESPONSE, AND GRID-ENHANCING TECHNOLOGIES

Q. WHAT NEAR-TERM SOLUTIONS DID THE COMPANY EVALUATE?

A. The Company explains that it only evaluated reconductoring, generation redispatch, or operating guidelines as a near-term solutions while longer-term transmission expansion is completed.[1] As outlined below, the Company admits that it did not evaluate the use of

[1] For example, see the January 16-17, 2024 hearing transcript in the 2023 IRP Update (Docket No. 55378) ("Hearing Transcript") at page 257: "we looked at alternatives such as operating guidelines, redispatch, and then reconductering and rebuilding." Also see the question and answer at pages 342-343: "Did the company evaluate whether storage as a transmission solution could overcome those transmission barriers?

battery storage, demand response, and grid-enhancing technologies as an alternative to the transmission expansion. As I explain in the following sections, these technologies, alone or in combination, offer significant potential to reduce or defer the need for transmission expansion capital investment. Battery storage and demand response can serve as both generating capacity resources and as solutions to alleviate localized transmission constraints, so they could reduce the need for both transmission upgrades and generating capacity.

Q. HOW CAN BATTERY STORAGE, DEMAND RESPONSE, AND GRID-ENHANCING TECHNOLOGIES REDUCE THE NEED FOR TRANSMISSION UPGRADES?

A. These solutions can be deployed in load pockets or other congested parts of the grid, alleviating the need for transmission upgrades to deliver power into those areas during short-duration peak demand periods or system contingency conditions. Alone or in combination, battery storage, demand response, and grid-enhancing technologies are ideal for meeting these needs, as these solutions can respond quickly enough to address contingency events.

Importantly, these solutions can defer the need for grid upgrades until the longer-term, higher-capacity transmission upgrades discussed in the next two sections of my testimony can be completed. These near-term solutions can also buy time for the Company to bring online more cost-effective generation and capacity resources, and the transmission required to deliver them to load.

A. Georgia Power did not evaluate how strategically-sited batteries can alleviate near-term grid upgrade needs as it completes long-term transmission expansion

A (Witness Grubb) We did not. In the transmission screening, we looked at -- as we mentioned this morning, redispatch, operating guidelines, reconductoring."

Q. WHY DID GEORGIA POWER NOT EVALUATE BATTERY STORAGE AS A TRANSMISSION SOLUTION?

A. The primary reason is that Georgia Power's transmission planning assumes batteries are either not providing power, or are charging, during peak demand periods. As a result, Georgia Power's transmission planning assumes batteries do not help and can actually exacerbate transmission constraints during peak periods. This assumption is flawed, as the charging and discharging of storage resources is economically dispatched in response to system needs, so that batteries never charge and almost always discharge during periods of need. In fact, FERC Order 2023 now requires transmission service providers like Georgia Power to allow storage interconnection customers to specify charging and discharging behavior,[2] reflecting that interconnection upgrades are typically not needed to accommodate charging because batteries can be dispatched so that they do not charge during periods of peak transmission system usage. Because it wrongly assumes batteries are off or even exacerbate overloads by charging during peak periods, when in reality they would mitigate transmission constraints through economic dispatch, Georgia Power's transmission planning misses opportunities for strategically-sited batteries to defer or eliminate near-term grid upgrade needs.

Q. DOES GEORGIA POWER DOCUMENT THE BATTERY CHARGING AND DISCHARGING ASSUMPTIONS IT USES IN ITS TRANSMISSION PLANNING?

A. Yes, these assumptions are shown in the Georgia Integrated Transmission System Ten-Year Plan included in IRP Appendix 3.[3] Table 14 shows that Georgia Power's transmission planning assumes batteries are off during summer peak conditions and fully charging during winter peak conditions. Georgia Power confirmed in response to discovery that in "Southern Company's base case models, battery resources are modeled off in summer peak," and "batteries are modeled as charging for winter in the off-the-shelf base cases."[4]

[2] FERC, *Order 2023*, (July 2023), *available at* https://www.ferc.gov/media/e-1-order-2023-rm22-14-000, at 17

[3] Section D (2024 GA ITS Ten-Year Plan (2025-2034) of the IRP Volume 3 Technical Appendix, page 260

[4] Georgia Power response to STF-GS-1-4a

This is consistent with the Company's responses to discovery in past IRPs, where it also explained that it did not evaluate the potential to use battery storage to reduce or eliminate the need for transmission upgrades[5] because the Company assumed they could charge during peak demand periods. The Company argued in the 2023 IRP Update that it did not evaluate batteries as a solution for transmission upgrades because the need to charge batteries causes them to serve as a load.[6]

Q. HOW DO BATTERIES HELP AVOID THE NEED FOR TRANSMISSION UPGRADES?

A. Due to batteries' speed of power dispatch, the ability of their power electronics to regulate voltage and reactive power and address local stability concerns, and their ability to be quickly deployed at points on the grid where they are needed, battery storage can be an effective alternative to transmission upgrades, particularly upgrade needs triggered by contingency conditions.[7] Batteries can almost instantly dispatch their output up or down to avoid causing thermal overloads on the transmission system. Batteries also serve as capacity resources, reducing the need for the Company's proposed generating capacity additions.

Q. CAN BATTERIES BE DEPLOYED QUICKLY ENOUGH TO MEET THE NEAR-TERM NEEDS CLAIMED BY GEORGIA POWER?

[5] Please see the Company's response to data request STF-GS-1-1 in the 2023 IRP Update (Docket No. 55378), attached to my testimony as Exhibit MG-2: "The Company did not study Battery Energy Storage Systems ("BESS") as options to reduce, defer, or eliminate the transmission upgrades identified in the 2023 IRP Update to facilitate the delivery of power from the proposed Plant Yates combustion turbines."

[6] For example, see Witness Grubb's statement in the Hearing Transcript in the 2023 IRP Update (Docket No. 55378) at page 343: "We don't usually look at batteries as a potential to remove transmission projects mainly because they have to be charged and so they serve as a load. So most of our transmission contingencies are not usually solved with a battery."

[7] See Brent Oberlin, *Storage as a Transmission Only Asset*, (May 2022), *available at* https://www.iso-ne.com/static-assets/documents/2022/05/a7_storage_as_a_transmission_only_asset.pdf, at 11-15; and Quanta Technology, *Storage as Transmission Asset Market Study*, (January 2023), *available at* https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf

A. Yes. Analysis from a 2024 Lawrence Berkeley National Laboratory report[8] shows that batteries tend to have the shortest time of any resource type between submitting an interconnection request and signing an interconnection agreement, with a median of less than 20 months, nearly a year less than gas generators. Many battery storage resources are already quite advanced in Georgia Power's interconnection queue, so in many cases they can be brought online even more quickly.

Battery resources tend to be easier to interconnect than other resources because batteries are highly modular and have small footprints so they can be strategically sited at optimal points on the grid to avoid interconnection costs or concerns about congestion, and can even mitigate interconnection or congestion concerns triggered by other new resources or loads. Batteries' small and modular footprint and flexibility in siting also helps mitigate land use and permitting challenges, in addition to facilitating interconnection. In contrast, other generating resources are more geographically limited in where they can be deployed, which tends to make interconnection more challenging.

In the 2023 IRP Update, Georgia Power correctly noted this benefit of storage, writing that "The time to construct BESS is shorter than other types of generation and, therefore, can be more quickly deployed to help meet the earlier capacity needs identified in the 2023 IRP Update. Moreover, the Company's Resource Mix Study, provided in the Technical Appendix, selects BESS as an economically optimal resource beginning in the winter of 2026/2027…"[9] Given that they can be deployed quickly, Georgia Power can use strategically-sited batteries as an interim solution to both its claimed transmission and generating capacity needs until it can complete longer-term high-capacity transmission upgrades.

[8] J. Rand *et al.*, *Queued Up: 2024 Edition*, *Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023*, Lawrence Berkely National Laboratory (Apr. 2024), https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_1.pdf, at 36.

[9] Direct Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush on behalf of Georgia Power Company in the 2023 IRP Update, Docket No. 55378, at 37

Q. DID GEORGIA POWER EVALUATE DEPLOYING BATTERIES IN LOAD POCKETS?

A. Georgia Power explained in the 2023 IRP Update that it was focused on deploying batteries at or near solar installations.[10] While deploying storage near solar resources can be an attractive solution for reducing renewable curtailment, only evaluating solar sites can lead to missed opportunities to locate batteries near expected loads to reduce the need for transmission upgrades into those areas. As noted above, given its small footprint and modular construction, storage can be deployed in optimal quantities and at optimal points on the grid to reduce or defer the need for transmission upgrades. For example, battery storage has been deployed in load pockets in Indianapolis,[11] San Diego,[12] New York City,[13] and other urban areas to offset the need for grid upgrades and support local reliability. Batteries could also be deployed at existing or retired generator sites to utilize the interconnection equipment and transmission capacity that exists at the site.

Q. DID GEORGIA POWER EVALUATE BATTERY STORAGE AS A POTENTIAL TRANSMISSION SOLUTION IN ITS PAST IRPs?

A. No. In response to data request STF-DEA-3-39 in the 2022 Georgia Power IRP (Docket No. 44160), which asked "Has the Company studied the potential transmission deferral, congestion relief and reliability benefits associated with the siting location of BESS?," Georgia Power responded:

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[10] For example, see page 35 of the Direct Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush on behalf of Georgia Power Company in the 2023 IRP Update, Docket No. 55378: "The Company proposes to add 178 MW of 4-hour duration lithium-ion BESS to existing Company-owned solar facilities at Robins and Moody Air Force Bases and 200 MW of BESS plus 200 MW of solar at a new site." Also see the hearing transcript at page 580: "(Witness Bush) That's correct. We are actually engaging many of the PPA providers for Georgia Power Company that have large solar sites, engaging them to find their interest in allowing us to put a battery there at that site, in conjunction with the interconnection and delivery service that already exists at that site."

[11] AES Indiana, *IPL and AES leaders official open first battery-based energy storage in MISO region* (July 12, 2016), https://www.aesindiana.com/ipl-and-aes-leaders-officially-open-first-battery-based-energy-storage-miso-region.

[12] SDG&E, *SDG&E Unveils World's Largest Lithium Ion Battery Storage Facility* (Feb. 28, 2017), http://newsroom.sdge.com/battery-storage/sdge-unveils-world%E2%80%99s-largest-lithium-ion-battery-storage-facility.

[13] Aaron Larson, *New York City's Largest Battery Energy Storage System Nears Completion*, POWER (June 22, 2023), https://www.powermag.com/new-york-citys-largest-battery-energy-storage-system-nears-completion/.

> No. Transmission deferral, congestion relief, or transmission reliability are not use cases evaluated for the 1000MW of BESS proposed to be deployed for generation resource reliability purposes. Georgia Power evaluated sites where the transmission system was least constrained in order to maximize the benefits (flexibility, capacity, production cost) at the lowest cost to customers.

In response to discovery in the 2022 IRP, Georgia Power also dismissed solutions like battery storage because it claimed that they were too small to meet the full need.[14] This ignores the ability to use a combination of battery storage, demand response, and grid-enhancing technologies to reduce or eliminate the need for grid upgrades. Even if a combination of these near-term solutions is insufficient to fully replace the need for transmission expansion, that does not mean they should not be pursued as a cost-effective option to reduce or defer need. These solutions provide significant value by enabling cost-saving changes in the generation mix and improvements in electric reliability to occur more quickly. Moreover, these interim solutions will continue to provide benefits even after long-term transmission solutions are completed, by continuing to alleviate congestion and improve reliability. As a result, they should not be viewed as alternatives, but rather as complements to the long-term solution of building new transmission lines.

Q. HOW DOES FEDERAL POLICY AFFECT THE ECONOMICS OF BATTERY STORAGE?

A. Yes. Stand-alone batteries are now eligible for a 30% Investment Tax Credit ("ITC") under the Inflation Reduction Act ("IRA") that became law in August 2022, and that credit can be increased to 40% or 50% if "energy community" or domestic content requirements are met. Prior to enactment of the IRA, only battery storage resources deployed at renewable generators receiving the ITC were eligible for the tax credit. Any brownfield site can qualify for the energy community bonus, giving Georgia Power significant flexibility to

[14] For example, see Georgia Power's response to data request STF-GDS-4-7.e. in Docket No. 44160, attached to my testimony as Exhibit MG-3, stating that "Alternative solutions such as energy storage or distributed energy resources have not been considered yet for various reasons." Those reasons include "the magnitude of storage or DER that would be needed makes those options untenable."

site batteries at optimal locations and receive at least a 40% ITC. Several parts of the state also qualify as energy communities because of their history of fossil fuel production or generation.[15]

B. <u>Demand response or rate design can serve as an interim solution to grid upgrade needs</u>

Q. DID GEORGIA POWER ADEQUATELY EVALUATE DEMAND-RELATED SOLUTIONS TO ITS CLAIMED NEEDS?

A. No, the Company did not adequately evaluate customer-based solutions to the claimed need for transmission upgrades. These solutions include non-firm or interruptible service rate options, the use of customer-sited resources like battery storage, or demand response programs that would compensate those customers for curtailing their load during periods of need. It appears that the Company only evaluates the use of demand response for alleviating system-wide generating capacity needs, not localized transmission constraints.[16] Demand response can be particularly valuable for mitigating the need for transmission upgrades to address reliability concerns triggered by generation, transmission, or double contingency events. For double contingencies in particular, it is likely that at least some of the new or existing customers in the load pockets would have more than enough time to reduce their load following the first contingency, or during the transitional period after the second contingency when transmission equipment can be operated at its contingency rating. In particular, many types of data centers have demonstrated an ability to quickly reduce load in response to dispatch or price signals during periods of need, as

[15] See U.S. Department of Energy, *Energy Community Tax Credit Bonus*, *available at* https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d

[16] See Georgia Power's response to STF-GS-1-8 and STF-GS-1-9 in the 2023 IRP Update (Docket No. 55378), attached to my testimony as Exhibit MG-4

those loads can be shifted later in time or to other data centers.[17] While data centers typically operate at high load factors, many computing loads are not time sensitive and thus can be curtailed during periods of need. A recent Duke University study quantified the opportunity for data centers to curtail demand or use their onsite backup generators to reduce or eliminate their load during periods of need,[18] and a recent U.S. Environmental Protection Agency regulatory interpretation indicates backup generators can be used for up to 50 hours per year "in non-emergency conditions to supply power for our nation's grid and maintain reliable service."[19]

If the proposed transmission upgrades are needed to address transmission system stability concerns, customer load reduction or the activation of battery storage can even be set to instantly trigger using a relay based on frequency or voltage. For example, some Loads Acting as a Resource in ERCOT are used as frequency-responsive contingency reserves because they are connected using relays that automatically shed load when frequency declines below a certain threshold.[20]

C. <u>The Company did not adequately evaluate the use of Grid-Enhancing Technologies as a near-term complement to proposed transmission upgrades</u>

Q. WHAT ARE GRID-ENHANCING TECHNOLOGIES, AND DID GEORGIA POWER ADEQUATELY EVALUATE THEM AS NEAR-TERM SOLUTIONS?

[17] For example, see Ana Radovanovic, *Our data centers now work harder when the sun shines and wind blows*, (April 2020), *available at* https://blog.google/inside-google/infrastructure/data-centers-work-harder-sun-shines-wind-blows/; and Energy Information Administration, *Tracking electricity consumption from U.S. cryptocurrency mining operations*, (February 2024), *available at* https://www.eia.gov/todayinenergy/detail.php?id=61364: "For example, in Texas, the grid operator ERCOT has created its Large Flexible Load (LFL) program, which enlisted up to 1,530 megawatts (MW) of large industrial consumers to curtail their use during peak demand periods. Cryptocurrency miners are major participants in the LFL program…."

[18] T. Norris, *et al.*, *Rethinking Load Growth Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*, (2025) *available at* https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf

[19] U.S. Environmental Protection Agency, *EPA Issues Clarification to Help Power Data Centers, Ensure U.S. Is the AI Capital of the World*, (May 1, 2025) *available at* https://content.govdelivery.com/accounts/USEPAAO/bulletins/3de6347

[20] ERCOT, *2023 Annual Report of Demand Response in the ERCOT Region*, available at https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=975814860, at 2

A. Dynamic line ratings ("DLR"), power flow control devices, topology optimization techniques, and similar grid-enhancing technologies[21] can be deployed quickly, typically within a matter of months,[22] so they can play an important role in alleviating near-term transmission constraints so new resources or loads can be interconnected while longer-term transmission upgrades are implemented. Georgia Power discusses grid-enhancing technologies in its 2025 IRP, and in its Ten Year Transmission Plan proposes the deployment of two smart valves as power flow controllers and one STATCOM device.[23] However, Georgia Power's Ten Year Transmission Plan does not propose the use of topology optimization or any dynamic line rating applications, and the Company acknowledges that it "does not currently have any operational DLR deployments on the System."[24] Given Georgia Power's claim of large and urgent grid upgrade needs to address reliability, load growth, and generation interconnection challenges, it should more thoroughly evaluate how these solutions, including greater deployment of power flow control devices, can be used as interim measures until longer-term upgrades are completed. Analysis by the Brattle Group found that 2,670 MW of additional wind capacity could be added in SPP by adopting DLR, power flow control devices, and topology optimization, more than doubling the amount of wind capacity that can be added while keeping curtailment at an acceptable level.[25] Brattle found a one-time investment of $85 million in these technologies would yield annual production cost savings of $175 million.

DLR allows more power to safely flow on transmission lines by accounting for how

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[21] Rob Gramlich, *Bringing the Grid to Life: White Paper on the Benefits to Customers of Transmission Management Technologies* (Mar. 2018), *available at* https://watttransmission.files.wordpress.com/2018/03/watt-living-grid-white-paper.pdf.

[22] *See* Idaho Nat'l Lab., *A Guide to Case Studies of Grid Enhancing Technologies*, 11, 26 (Oct. 2022), https://inl.gov/wp-content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf.

[23] See Georgia Power response to DEA-2-10, Attachment A

[24] See Georgia Power response to STF-GS-2-13

[25] Bruce Tsuchida, Stephanie Ross, Adam Bigelow, *Unlocking the Queue with Grid-Enhancing Technologies*, at 8 (February 2021), *available at* https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

ambient weather conditions affect the thermal limits of those lines. Transmission line ratings are typically based on worst case weather assumptions: hot weather with full sun and no wind cooling the line. DLR devices measure the actual thermal limit of transmission lines, which under most weather conditions are much higher than the limits based on those worst-case assumptions.

Power flow control devices, also known as Flexible Alternating Current Transmission Systems devices, can also be deployed quickly to increase interconnection capacity on the existing transmission system. These are power electronics-based devices used to adjust the power transfer capabilities of the system and improve stability or controllability of the system under critical conditions. Topology optimization plays a similar role by taking specific transmission lines out of service to redirect power flow away from congested transmission elements and onto more optimal paths. Both of these solutions can play an important role in alleviating constraints during transmission contingency events.

III. GEORGIA POWER SHOULD ADOPT BETTER TRANSMISSION PLANNING PRACTICES TO IDENTIFY MORE OPTIMAL LONG-TERM SOLUTIONS THAT PROTECT CONSUMERS FROM UNCERTAINTY IN LOAD GROWTH AND OTHER FACTORS

Q. WHAT TYPE OF TRANSMISSION PLANNING SHOULD GEORGIA POWER ADOPT?

A. More optimal solutions for ratepayers can be identified using proactive multi-value transmission planning, which is the best practice used in other regions. Given that Georgia Power indicates it is currently developing "additional planning considerations and process enhancements,"[26] it is important for these best practices to be incorporated as part of those enhancements. I report I co-authored identified the following principles of proactive multi-value transmission planning:[27]

[26] Georgia Power, *2025 IRP*, page 113; and Georgia Power response to STF-GS-2-9

[27] Pfeifenberger, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, BRATTLE GRP. & GRID STRATEGIES LLC, at iv (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

1. Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.

2. Account for the full range of transmission projects' benefits, and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.

3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

4. Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.

5. Jointly plan across neighboring interregional systems to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

Q. WHAT TRANSMISSION BENEFITS SHOULD BE INCLUDED IN MULTI-VALUE TRANSMISSION PLANNING?

A. FERC Order 1920 identified the following seven categories of benefits provided by transmission:

(1) avoided or deferred reliability transmission facilities and aging infrastructure replacement;

(2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin;

(3) production cost savings;

(4) reduced transmission energy losses;

(5) reduced congestion due to transmission outages;

(6) mitigation of extreme weather events and unexpected system conditions; and

(7) capacity cost benefits from reduced peak energy losses.[28]

At minimum, Georgia Power's transmission planning should account for these seven categories of benefits. As I outline below, Georgia Power should also use scenario-based planning to assess the value of transmission for protecting ratepayers against uncertainties in load growth, generation costs, fuel costs, regulations, and other factors. This is particularly important for Georgia Power as it currently faces major uncertainty about those factors over the 20-year IRP planning horizon.

Q. DOES GEORGIA POWER USE PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. The process outlined in the Transmission Planning Description and Process document included in Appendix 3 is neither proactive nor multi-value transmission planning for multiple reasons.

First, it is not sufficiently proactive. The 10-year horizon for Georgia Power's transmission planning[29] falls well short of the 20-year horizon required by FERC Order 1920, as discussed below. Given that Georgia Power's IRP uses a 20-year horizon for generation planning, a 20-year transmission planning horizon would also allow more synchronization, or at least iteration, between generation and transmission planning. I offer additional suggestions below regarding how Georgia Power can better iterate between generation and transmission planning to produce a truly "integrated" Integrated Resource Plan.

Moreover, Georgia Power's transmission planning process assumes that the bulk of generating capacity additions will be located at existing generator sites where it can be

[28] Order 1920, at P 720

[29] Georgia Power IRP Technical Appendix Volume 3, Transmission Planning Description and Process, at 15: "The transmission planning process follows an iterative process with a planning horizon looking 10 years into the future. However, due to the dynamics of the assumptions and data used to develop the latter years of the system model, project proposals are usually fully developed for the first five years only (considered to be the near-term planning horizon). These projects and their mutual effects are tested throughout the full ten-year period. For issues in the last five years of the planning horizon, viable projects are identified but not fully scoped, estimated and budgeted unless long lead-time items such as right-of-way acquisition are included."

interconnected and delivered to load with no transmission upgrades. As Georgia Power documented in the 10-year transmission plan filed with the IRP:

It is not yet known where any new generation resources will be located after 2029. To balance load and generation in the base cases as load grows and existing fossil units are retired, it is necessary to make assumptions for the locations of generation to be added. When the cases are created, the "expansion units" listed in Table 9 are included as needed. The sites chosen for these units are locations where fossil units have been or are expected to be retired, since existing transmission connections are (or previously have been) adequate, and therefore are expected to cause minimal new constraints. No projects were attributed to the expansion units included in the base cases as shown below.[30]

In reality, at least some of these generators will require some transmission capacity expansion, so this assumption greatly understates the actual transmission need. As outlined later in this section, a better practice used by other utilities to iteratively co-optimize generation and transmission planning is to make rough initial assumptions about the likely location of future resources, based on historical patterns and resource locations, and then refine those over time as specific generators are identified.

Second, all of the benefits Georgia Power's transmission planners assess are related to reliability, not economic benefits or other benefits that are typically evaluated in multi-value planning or even standard utility practice transmission planning.[31] Other parts of the Georgia Power's transmission planning document confirm that it only plans transmission to resolve reliability problems: "For problems to be identified, situations exist where the system will operate in an unacceptable manner (as defined by the performance guidelines)."[32] Furthermore, no production cost models are included in the many models the transmission planning document lists as being used by Georgia Power transmission planners, which is not standard utility practice for transmission planning. The economic

[30] Georgia Power IRP Technical Appendix Volume 3, Section D (2024 GA ITS Ten-Year Plan (2025-2034), at 257

[31] Georgia Power IRP Technical Appendix Volume 3, Transmission Planning Description and Process, at 23-25

[32] *Id.*, at 23

dispatch of generators is only used as an input into load flow models, and not an output of the models as it would be in the production cost models used in standard utility practice.[33] In response to discovery in this docket, Georgia Power confirms that its planning methods do not account for how transmission enables production cost savings or potential savings from reductions in the need for generator capacity.[34] Georgia Power does indicate that it uses strategic transmission planning processes, which are often "separate and incremental transmission evaluations as the need for those types of evaluations arise" to identify "long lead time projects that solve multiple constraints on the transmission system,"[35] While it is good that the Company recognizes the benefits of multi-value planning, it does not appear that production cost modeling or other robust tools for multi-value quantitative benefit-cost analysis are used in these strategic transmission studies, and regardless Georgia Power should use multi-value methods in its standard transmission planning processes. Georgia Power's standard planning methods focus on single problems, with different problem statements for reliability, load growth, and generator interconnection,[36] preventing the identification of multi-value solutions or portfolios of network solutions, two of the essential aspects of proactive multi-value planning identified above that help minimize cost and maximize benefits to ratepayers.

Q. DO TRANSMISSION PLANNERS IN OTHER REGIONS ACCOUNT FOR TRANSMISSION BENEFITS OTHER THAN RELIABILITY?

A. Yes. The Company's analysis is highly unusual in that it does not account for how

[33] *Id.,* at 32: "Economic Dispatch Program: The Economic Dispatch Program was developed by SCS to interact with the Power Technologies Inc. load flow program, PSS/E. The program calculates an economic dispatch for a given load and spinning reserve requirement specified by the transmission planners and is based on the theory that the most economical dispatch is obtained by operating all on-line units at the same incremental cost (lambda). The transmission planners specify information to the program through terminal interaction and two data files with pertinent information on the availability of units, in-service date, retirement date, must run status, power generation limits, generator cost data, etc. The program allows the transmission planners to input the appropriate economic dispatch directly into files for future use with the PSS/E program."

[34] Georgia Power response to STF-GS-1-2

[35] Georgia Power response to STF-GS-2-6

[36] Georgia Power IRP Technical Appendix Volume 3, Transmission Planning Description and Process, at 16

transmission upgrades provide production cost savings by reducing transmission losses and allowing lower-cost generation to displace higher-cost resources. Production cost savings are typically one of the primary benefits transmission planners account for when evaluating benefit-cost ratios for transmission projects and refining transmission plans. As FERC noted in the proposed rulemaking that led to Order 1920, "Most regional transmission planning processes currently estimate production cost savings."[37] Failing to account for that benefit understates the value of transmission, resulting in an underinvestment in transmission that harms ratepayers.

A report I co-authored provides many examples of how transmission planners in other regions account for economics and other benefits.[38] The results of studies by other grid operators confirm that by only looking at reliability, Georgia Power's benefit analysis is only capturing a small share of transmission's total benefits. For example, analysis by the Southwest Power Pool ("SPP") found that reliability benefits accounted for $3 billion out of the total benefits of over $27 billion from its recent transmission investments, or only 11% of the total benefits of transmission.[39] SPP found production cost savings totaled over $20 billion, or 76% of the total benefits.

Production cost modeling is also a valuable tool for refining transmission expansion plans by testing the benefit-cost ratio of alternative solutions. Georgia Power acknowledges that under its current planning methods, "the benefit-to-cost analysis performed by the Company is an iterative and qualitative analysis."[40] Production cost modeling would enable quantitative and not just qualitative benefit-cost analysis, which will likely result in

[37] See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC ¶ 61,028, 18 CFR Part 35, Dkt. No. RM21-17-000 (Apr. 21, 2022), https://www.ferc.gov/media/rm21-17-000, at paragraph 199

[38] Pfeifenberger, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, BRATTLE GRP. & GRID STRATEGIES LLC, Appendix D (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

[39] Sw. Power Pool, *The Value of Transmission – A 2021 Study and Report by Southwest Power Pool* (Mar. 31, 2022), https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf, at 29.

[40] Georgia Power response to STF-GS-2-8(a)

better economic and reliability outcomes for ratepayers by more rigorously evaluating alternatives to identify more optimal transmission solutions.

Q. WHAT ARE THE BENEFITS OF PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. Proactively planning a portfolio of transmission projects that meets multiple long-term needs is much more efficient than a reactive process that meets shorter-term needs with more incremental costly investments. This is largely because transmission investment offers large economies of scale, as documented below, with higher-voltage and double-circuit lines carrying many times more power than lower-voltage lines with a less than proportional increase in cost.

Multi-value transmission planning is more efficient as it allows the selection of grid upgrades that simultaneously meet multiple objectives in providing economic, reliability, and generator interconnection benefits. Georgia Power's current siloed process, in which reliability transmission projects are planned separately from generator interconnection projects, misses opportunities to meet both needs with the same projects more efficiently. The benefits of proactive multi-value planning relative to reactive approaches are summarized in the table below.

Table 1: Benefits of integrated proactive multi-value planning vs reactive queue-driven transmission investment

Problem with reactive approach driven by interconnection queue studies	How integrated proactive multi-value planning solves problem
Transmission solutions tend to be inefficient smaller, short-term fixes	Higher-capacity upgrades to meet longer-term need realize economies of scale in transmission
Building major network upgrades takes longer than it takes to build a generator	Transmission is ready when generation comes online
Generators have little incentive to pay for upgrades that also benefit other users, so they drop out of queue	Broadly allocate the cost of network upgrades, reflecting that they provide various benefits to many users

Generators face uncertain upgrade costs, and when they drop out of the queue costs change for other generators	Network upgrade costs are not assigned to generator
Does not plan transmission to new resource areas	Builds transmission in anticipation of generation
Interconnection upgrades sub-optimally planned separately from reliability and economic upgrades	Optimizes transmission build to maximize all benefits

Q. HOW CAN PROACTIVE PLANNING PROTECT RATEPAYERS FROM RISK?

A. Currently there is exceptionally high uncertainty regarding load growth, load patterns, the cost of different generating resources, potential regulations, the availability of thermal generation during periods of peak demand, and fuel prices. In that environment, positioning oneself to be able to pivot as needed is extremely valuable.

Transmission is an important mechanism to protect consumers against all types of uncertainty, including unpredictable volatility in the price of fuels used to produce electricity. Transmission can alleviate the negative impact of fuel price fluctuations on consumers by making it possible to buy power from other resources. As utilities Xcel and ITC noted in an approved application to build a transmission line in Minnesota, "[A] robust regional transmission system is also key to enabling access to a diverse mix of generation resources, which in turn allows customers to access the least expensive power available at any given time."[41]

Georgia Power can plan a more risk-averse transmission system by conducting generation and transmission planning for scenarios and sensitivities with high renewable and high load growth. This would build on the high solar scenario Georgia Power has run, and will allow identification of which transmission corridors are least regrets in that they have high need under a range of sensitivities.

[41] Northern States Power Company and ITC Midwest LLC, *Application to the Minnesota Public Utilities Commission for a Certificate of Need for the Huntley-Wilmarth 345 kV Transmission Line Project*, at 8, MPUC Docket No. E-002, (January 2018) https://www.huntleywilmarth.com/staticfiles/microsites/hw/HW-Certificate-of-Need-Application.pdf.

Proactive transmission planning is necessary to protect against high cost surprises on the generation side of the ledger. Because generation costs account for the majority of ratepayers' cost of electricity, while transmission is only about 10-15%, it is prudent to adequately invest in transmission to protect against higher generation costs. The lead time for transmission is long, much longer than the timeline for building generation, so it must be planned in advance of perfect knowledge about generating capacity additions and their precise locations. As discussed below, the "chicken and egg" time mismatch between building transmission and generation was the impetus for other regions to move to proactive transmission planning over the last several decades. I testified here in the 2016 IRP proceeding that Georgia Power should proactively plan transmission. If Georgia had started planning high-voltage transmission expansion then, that transmission and the low-cost generation it enabled would have been in service by now.

Q. CAN TRANSMISSION HEDGE AGAINST LOAD GROWTH UNCERTAINTY?

A. Yes. Uncertainty regarding load growth is extremely high at the moment. Many planned additions of large loads are being canceled, including battery[42] and electric vehicle factories,[43] data centers,[44] and other large loads. Uncertainty regarding federal incentives for domestic manufacturing are adding to the uncertainty regarding large load growth. Potential changes to federal incentives for electrification of transportation and building heating may also affect the rate at which those technologies are adopted and thus the residential and commercial load growth trajectory. There is significant uncertainty about growth in data center electricity demand for artificial intelligence.[45]

[42] M. Lewis, *FREYR kills plans to build a $2.6 billion battery factory in Georgia*, (February 2025), *available at* https://electrek.co/2025/02/10/freyr-battery-factory-georgia/

[43] S. Osaka, *A stunning number of electric vehicle, battery factories are being canceled,* (April 2025) *available at* https://www.washingtonpost.com/climate-environment/2025/04/03/ev-factories-canceled/

[44] N Rommel., *Microsoft pauses construction on parts of Mount Pleasant site again*, (March 2025), *available at* https://www.wpr.org/news/microsoft-pauses-construction-on-parts-of-mount-pleasant-site-again

[45] B. Geman, *DeepSeek shakes up the energy-AI equation,* (January 2025) *available at* https://www.axios.com/2025/01/28/deepseek-ai-model-energy-power-demand

The rapid increase in demand for large load interconnection over the last several years also appears to be driving speculative interconnection requests as companies shop around for available interconnection points, so it is difficult to predict large customer interconnection success rates. Historical interconnection completion rates may not accurately predict success rates for entirely new industries, like artificial intelligence data centers. Utility load growth projections deserve extra scrutiny because utilities have a strong financial incentive to overstate load growth to increase their profits with larger rate-based investments in generating capacity.

Q. ARE THERE ADDITIONAL UNCERTAINTIES REGARDING THE AMOUNT OF ENERGY AND CAPACITY NEEDED FOR NEW LARGE LOADS?

A. Yes. Many developers of new large loads, particularly data centers, have corporate renewable or carbon reduction commitments. To meet these goals, these companies typically purchase their own energy sources to serve their needs. As a result, demand for both energy and capacity may be lower than Georgia Power has indicated. Further adding to the uncertainty regarding load growth, some of these corporate goals are in flux as companies scale up data centers. Moreover, as discussed in the preceding section, if properly incentivized to do so, some data centers may have the ability to provide demand response that greatly reduces their peak demand.

Q. HAVE TRANSMISSION'S ECONOMIES OF SCALE BEEN DOCUMENTED?

A. Yes. Higher-voltage transmission lines offer large economies of scale and allow more efficient use of right-of-way due to their higher capacity. For example, MISO's annual estimate of transmission costs provides data illustrating the large economies of scale for higher-voltage and double-circuit transmission, which are used to calculate the results shown in Table 2 below.[46] On a $/MW-mile basis, which reflects the average cost of

[46] Midcontinent Indep. Sys. Operator, *Transmission Cost Estimation Guide for MTEP24* (May 2024),

transmission to deliver one MW one mile, double-circuit 230 kV transmission is 53% less costly than single-circuit 115 kV, and 500 kV is 71% less costly than single-circuit 115 kV transmission.

Table 2: Economies of scale for higher-voltage transmission lines

	Voltage (kV)	69	115	138	161	230	345	500	765
Single Circuit	$M/mile	$1.7	$1.9	$2.0	$2.1	$2.2	$3.5	$4.4	$5.5
	MW or MVA	140	329	394	460	657	1792	2598	6625
	$/MW-mile	**$12,143**	**$5,775**	**$5,076**	**$4,565**	**$3,349**	**$1,953**	**$1,694**	**$830**
Double Circuit	$M/mile	2.5	2.8	2.9	3	3.6	5.8	NA	NA
	MW or MVA	280	658	788	920	1314	3584	NA	NA
	$/MW-mile	**$8,929**	**$4,255**	**$3,680**	**$3,261**	**$2,740**	**$1,618**	**NA**	**NA**

Q. BASED ON THESE ECONOMIES OF SCALE, WHAT TYPE OF TRANSMISSION SHOULD GEORGIA POWER PLAN?

A. Higher-voltage and double-circuit transmission is significantly more cost effective, so the Company should primarily focus on higher-capacity transmission solutions, like the 500 kV network proposed in the IRP. Long-term proactive multi-value transmission planning is the best mechanism to achieve these economies of scale. This analysis should use scenarios to plan for long-term changes in load and generation and optimally meet reliability, economic, and generator interconnection needs. These approaches will minimize the total cost of generation plus transmission by building the optimal amount of transmission to maximize net benefits for ratepayers.

Until that new planning process is implemented, a prudent step would be to review at least

https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf (Table 1 was prepared using the reported Power rating (MVA) capacity data in Table 3.1.5 on page 33 and the estimated costs for Arkansas reported in Tables 4.1.1 and 4.1.2 on pages 38–39. Costs for Arkansas were used as they are in the middle of the range of MISO's cost estimates by state, and are likely to be more representative of costs in the Southeast. The Power rating (MVA) capacity data for the Double Circuit are twice the capacity for the Single Circuit.).

some of the Company's proposed investments in lower-voltage transmission assets to assess if they could be more economically deployed at higher voltage or in a double-circuit configuration to better meet long-term needs. To ensure this review does not delay the completion of urgently needed upgrades, this can be done in parallel while Georgia Power proceeds planning, engineering, permitting, and land acquisition for the proposed projects. This review should also assess whether the lower-voltage and single-circuit transmission upgrades interfere with the ability to deploy higher-voltage transmission on that valuable right-of-way to meet future load growth or generation needs.

At minimum, Georgia Power should assess the feasibility of building the towers, conductors, and insulators so that a. a second circuit can be added later without rebuilding the towers, and/or b. the line can be converted to 230 kV operation if the need materializes by replacing terminal substation equipment such as transformers and circuit breakers. Transmission lines typically have lifetimes of more than 50 years, so including this optionality is generally a prudent investment. This approach has been successfully used by other utilities. For example, the towers for new lines in MISO[47] and ERCOT[48] were built with the capability to add a second circuit, and that need quickly materialized. This optionality is likely to be extremely valuable for hedging load growth uncertainty and other risks, as under many likely scenarios there will be a much greater need for transmission than accounted for under Georgia Power's current planning process. For example, if new loads with high load factors materialize, Georgia Power will need low-cost energy from solar resources in south Georgia to cost-effectively serve their need for energy.

Q. ARE THERE SPECIFIC AREAS OR PROJECTS IN GEORGIA POWER'S PLAN THAT MAY BENEFIT FROM AN EVALUATION OF HIGHER-CAPACITY

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[47] Minnesota Electric Transmission Planning, *Transmission Projects Report 2009, available at* https://www.minnelectrans.com/documents/2009_Biennial_Report/html/Ch_6_Needs_Sec_6.5_Twin_Cities_6.5.10.htm

[48] ERCOT, *Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study, Attachment A,* (April 2008) *available at* https://www.nrc.gov/docs/ML0914/ML091420467.pdf

SOLUTIONS?

A. Yes. What follows is an illustrative and non-exhaustive list of examples of projects that may merit evaluation to assess if higher-capacity solutions are more optimal for meeting long-term needs. It appears that few if any of these higher-capacity alternatives were evaluated as part of Georgia Power's transmission planning process that led to the development of the Ten-Year Transmission Plan included in the IRP.[49] As explained in more detail above, moving to proactive multi-value scenario-based transmission planning, ideally iterated with generation planning, is essential for optimally identifying which upgrades are needed. A more proactive and multi-value transmission planning approach might have selected some of these alternatives as a more cost-effective way to meet long-term needs and maximize net benefits. Some of the conceptual proposals below may not make sense for reasons like local siting issues, local need, the line not being the limiting element for transmission flows under a range of foreseeable grid topologies, etc., but they are intended to illustrate the types of solutions Georgia Power should be evaluating to ensure it efficiently meets ratepayers' long-term needs:

The proposed Pio Nono 230 kV upgrade[50] could be extended further south from its proposed termination at the Pitts substation. This could include extending it to North Tifton or even further south. Georgia Power could also assess the feasibility and net benefits of building this upgrade at 500 kV instead of 230 kV. These potential solutions would facilitate the delivery of more solar to areas experiencing load growth in north Georgia.

In that same area, the proposed Fitzgerald-Pitts 115 kV rebuild[51] could be evaluated as a 230 kV or 230 kV-capable solution, and could potentially extend south past Fitzgerald to intersect with existing 230 kV lines at Stump Creek or near Harding. Similarly, the

[49] See Georgia Power's response to STF-GS-2-7

[50] Georgia Power IRP Appendix 3, 2024 GA ITS Ten-Year Plan (2025-2034), page 235

[51] *Id.*, at 154

proposal to rebuild 41 miles of the Bonaire Primary - Eastman Primary 115 kV Line[52] could be assessed for 230 kV or 230 kV-capable design. As another example in that area, the proposal to rebuild 15.8 miles of 115 kV from Jackson Lake to Lloyd Shoals and Jackson Lake to South Covington Junction could be assessed for 230 kV conversion.[53]

A bit east of there near Sandersville, the proposal to rebuild the Sandersville #1 - Wadley Primary 115kV line could be evaluated for the viability of a 230 kV or 230 kV-capable solution.[54] Similarly, the existing low-voltage line from Wrightsville to Sandersville could be evaluated for rebuilding to 230 kV. The proposal to rebuild 115 kV lines between Sandersville, Dublin, and Gordon could be assessed for a 230 kV or 230 kV-capable solution to help move more solar western towards the Atlanta load center."[55][56][57]

To facilitate solar interconnection in south Georgia, the existing 230 kV and 115 kV lines between North Tifton and Valdosta could be converted to two 230 kV lines, or even one 500 kV line. In that area, the proposal to rebuild 38 miles of 115 kV from Pine Grove to the Pearson tap[58] could be assessed for 230 kV or 230 kV capable, and the 230 kV line could extend through Pearson up to Douglas.

[52] *Id.*, at 180

[53] *Id.*, at 185

[54] *Id.*, at 142

[55] *Id.*, at 93

[56] *Id.*, at 114

[57] *Id.*, at 211

[58] *Id.*, at 221

Finally, the proposed 115 kV rebuild from Barneyville to East Moultrie also seems ripe for a potential 230 kV solution,[59] and the existing 115 kV line from near Thomasville to Moultrie could also be assessed for 230 kV.

Q. HAVE OTHER REGIONS SUCCESSFULLY USED PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. Yes, and they have found that this type of planning minimizes the total cost to ratepayers of generation plus transmission by building the optimal amount of transmission. Over a decade ago, the Midcontinent Independent System Operator ("MISO") used a proactive multi-value transmission planning process to identify a holistic portfolio of transmission upgrades, called the Multi-Value Projects ("MVPs"), that were needed to meet reliability, economic, and state renewable energy policy needs.[60] All but one of those lines have since been completed, and analyses have confirmed that those projects are providing large net benefits.[61] MISO's process was informed by Texas's success in using proactive transmission planning to build the Competitive Renewable Energy Zone projects, a portfolio of upgrades that allowed the state to double its use of renewable energy.[62] SPP also adopted a proactive multi-value transmission planning approach, and two subsequent studies have confirmed that those upgrades are providing large net benefits by meeting a range of economic and reliability needs.[63]

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[59] *Id.*, at 156

[60] Midcontinent Indep. Sys. Operator, *Multi Value Project Portfolio–Results and Analyses* (Jan. 10, 2012), https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.

[61] Midcontinent Indep. Sys. Operator, MTEP17 MVP Triennial Review–A 2017 Review of the Public Policy, Economic, & Qualitative Benefits of the Multi-Value Project Portfolio (Sept. 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf.

[62] *See, e.g.*, Lasher, *The Competitive Renewable Energy Zones Process*, ERCOT (Aug. 11, 2014), https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

[63] *See* Sw. Power Pool, *The Value of Transmission – A Report by Southwest Power Pool* (Jan. 26, 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf; *see also* Sw. Power Pool, *The Value of Transmission – A 2021 Study and Report by Southwest Power Pool* (Mar. 31, 2022), https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf.

Proactive multi-value transmission planning has also been successfully used by vertically-integrated utilities outside of Regional Transmission Organizations. For example, Nevada Power's Greenlink Nevada project is designed to provide a range of benefits across categories including reliability, economics, proactively interconnecting a diverse portfolio of renewable energy resources, and expanding ties to neighboring grid operators.[64] Xcel's Colorado Power Pathway is another example of proactive transmission planning to realize multiple benefits.[65] Finally, Duke has proposed moving to multi-value transmission planning.[66]

In addition, the IRPs conducted by PacifiCorp, Xcel's Minnesota utility Northern States Power, and Xcel's Colorado utility Public Service Company of Colorado co-optimize transmission planning with generation planning for truly "integrated" resource planning. Vertically-integrated utilities like Georgia Power can synchronize generation and transmission planning. This avoids any risk that transmission developed in anticipation of market interest from generators will not be fully subscribed, though pro-actively planned transmission lines in Texas and other areas without vertically-integrated utilities have quickly been fully subscribed.

Q. WHAT ARE COMMON REASONS FOR NOT USING PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. Siloed and reactive planning processes are often used so costs for different types of transmission can be assigned to different users of the grid. However, allocating the cost of upgrades to the bulk transmission network is challenging because the bulk transmission

[64] NV Energy, *Greenlink Nevada* (Apr. 8, 2021), https://goed.nv.gov/wp-content/uploads/2021/05/Greenlink-Nevada-Presentation-4-08-21.pdf.

[65] Xcel Energy, *Colorado's Power Pathway* (last visited Mar. 24, 2023), https://www.coloradospowerpathway.com/project-description/.

[66]CTPC, *Multi-Value Strategic Transmission Planning*, (November 2023), *available at* http://www.nctpc.org/nctpc/document/REF/2023-12-08/Multi-Value%20Strategic%20Transmission%20Planning%20Process%20draft%2011-13-2023.pdf

network allows all generators and loads to efficiently and reliably deliver power. In contrast, the cost of direct interconnection facilities, analogous to the driveway a resource uses to connect to the transmission system, is always allocated to the interconnecting resource as that cost can be directly attributed to that resource and network power does not flow across that transmission element.

Network upgrade costs assigned to generators ultimately flow to ratepayers when they are rolled into the cost of the new generation. Generators must recover network upgrade costs, as well as the cost of interconnection study fees, by charging a higher price when Georgia Power procures new renewable and storage resources, either through a power purchase agreement or an acquisition. As a result, developing a workable planning and cost allocation method that minimizes the cost and maximizes the net benefits of network upgrades is more important, as the costs will flow to ratepayers regardless of how they are initially allocated.

Network upgrades are also a public good, in that all users of the transmission system benefit from them, including competing generators. As a result, interconnecting generators have little incentive to pay for network upgrades, which has driven the extremely high dropout rate in the interconnection queues of Southern Company and other grid operators. Assigning major network upgrade costs to an interconnecting generator is analogous to charging the next car entering a crowded highway the full cost of adding another lane. Proactively planning the needed network upgrades and broadly allocating the cost to ratepayers is a more efficient and workable policy, similar to how costs for other public goods like roads and sewer systems are allocated. While assigning network upgrade costs to interconnecting generators can theoretically induce generators to locate in parts of the grid where less costly upgrades are needed, the same benefit can be obtained by synchronizing generation and transmission planning and then broadly allocating network transmission costs to ratepayers, which is more workable than assigning upgrade costs to generators.

Q. DOES PROACTIVE PLANNING REDUCE INTERCONNECTION COSTS?

A. Yes. Proactive planning yields major savings by realizing economies of scale in transmission investment. Proactive planning allows investment in higher-capacity network transmission solutions that are more cost-effective for meeting longer-term needs than the lower-capacity upgrades that result from reactive transmission expansion processes, like the interconnection queue. The PJM grid operator recently found that proactive transmission planning could integrate 12.4 GW of offshore wind resources along with 14.5 GW of onshore wind, 45.6 GW of solar, and 7.2 GW of storage, for a total of just $2.2 billion.[67] This equates to a cost of $27/kilowatt for new generation capacity, a fraction of the cost found through interconnection queue studies. For example, a Brattle Group analysis of PJM queue study results show $1.3 billion in total identified transmission upgrades for integrating 5.6 GW of PJM offshore wind resources alone,[68] which equates to a cost of $415/kilowatt, 15 times greater than costs under PJM's proactive plan. Other analyses found that integrating 15.5 GW of offshore wind under today's rules would lead to $6.4 billion in upgrades,[69] at a cost of $236/kilowatt.

Similarly, a proactive planning effort in New Jersey for offshore wind resulted in selections of onshore transmission upgrades that save New Jersey ratepayers approximately $1 billion for 6,400 MW of additional offshore wind, a two-thirds reduction relative to the costs identified through PJM queue studies.[70]

Q. IS A REFORMED TRANSMISSION PLANNING APPROACH NEEDED FOR

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[67] PJM Interconnection, *Offshore Wind Transmission Study: Phase 1 Results*, 16, Scenario 6 (Oct. 19, 2021), https://pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

[68] Pfeifenberger, et al., *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report*, N.J. BD. OF PUB. UTILS., 180, Table A-2 (Oct. 26, 2022), https://www.brattle.com/wp-content/uploads/2022/10/New-Jersey-State-Agreement-Approach-for-Offshore-Wind-Transmission-Evaluation-Report.pdf.

[69] Burke, et al., *Offshore Wind Transmission White Paper*, BUS. NETWORK FOR OFFSHORE WIND, 40 (Oct. 2020), https://gridprogress.files.wordpress.com/2020/11/business-network-osw-transmission-white-paper-final.pdf.

[70] Pfeifenberger, *supra* at 92, Figure 4.

GEORGIA POWER?

A. Yes, proactive multi-value planning of major transmission upgrades will alleviate the current burden from trying to plan high-capacity network elements through reactive processes like the generator interconnection queue. While FERC recently required utilities to move to a cluster interconnection study approach, which offers incremental improvements over a serial approach in which interconnection applications are studied one at a time, it still fails to address the fundamental problems that interconnecting generators have little incentive to pay for grid upgrades that are public goods, and that transmission planned to interconnect generators does not optimize economic and reliability benefits.

Other regions have found that interconnection queues, even with the use of cluster studies, are inadequate for addressing large-scale changes in the transmission system driven by changes in the generation mix, as I explained in a recent report.[71] Across the country, interconnection queues have ballooned to around 2,600 GW of generation under study, as they have failed to efficiently drive network transmission development.[72] MISO has twice successfully used proactive multi-value planning to drive major transmission upgrades[73] when its interconnection queue has gotten bogged down with the same vicious cycle of problems that are plaguing interconnection queues across the country.

Q. WHAT ARE THE DRAWBACKS OF RELYING ON THE INTERCONNECTION QUEUE INSTEAD OF PROACTIVE PLANNING?

A. Relying on the interconnection queue instead of proactive planning causes high network

[71] Goggin, et al., *Disconnected: The Need for a New Generator Interconnection Policy*, AM. FOR A CLEAN ENERGY GRID (Jan. 12, 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf.

[72] Berkeley Lab, *Generation, Storage, and Hybrid Capacity in Interconnection Queues – Projects in the Interconnection Queues for ISOs and Utility Service Territories*, Electricity Markets & Policy, https://emp.lbl.gov/generation-storage-and-hybrid-capacity.

[73] *See* Ethan Howland, *MISO board approves $10.3B transmission plan to support 53 GW of renewables*, UTILITY DIVE (July 26, 2022), https://www.utilitydive.com/news/miso-board-transmission-plan-midcontinent-renewables/628108/ (In addition to the MVPs discussed above, last year, MISO approved a portfolio of Long-Range Transmission Plan projects that were developed using a similar proactive multi-value planning approach).

upgrade costs, which drive developers to propose speculative projects, which results in a high dropout rate, which results in restudies for projects remaining in the queue, which introduces uncertainty to initial cost estimates and drives further withdrawals when updated costs are published for those other generators, which in turn drives further delays, cost, cost uncertainty. As noted above, all of these costs ultimately flow through to ratepayers, as these costs are recovered through a higher purchase price when the resources are contracted by Georgia Power.

Q. CAN USING PROACTIVE TRANSMISSION PLANNING INSTEAD OF A REACTIVE APPROACH HELP MITIGATE THE IMPACT OF INFLATIONARY COST PRESSURES?

A. Yes. As I explained above, economies of scale greatly reduce the cost of proactively planned transmission, as a small number of high-voltage transmission lines can carry the same amount of power as many lower-voltage lines, saving ratepayers money by reducing material and labor expenses. This is particularly valuable given current inflationary cost pressures on a range of inputs, including steel and other metals used to build transmission towers and conductors, as well as labor shortages.

Proactive planning also reduces the cost and time burden of planning grid upgrades. Nationally, utilities and generation developers are facing significant shortages of qualified engineers to run interconnection studies due to the ballooning interconnection queues. A better use of this scarce resource is to let transmission planners proactively plan transmission, instead of repeatedly running reactive interconnection studies and restudies for generators that almost always drop out of the queue when they are assigned the cost of building major network upgrades.

Q. HOW SHOULD TRANSMISSION PLANNING BE INCORPORATED INTO IRPS?

A. For an IRP process to truly be "integrated," it must assess the multiple ways in which transmission affects generation plans, and how generation plans affect the need for transmission, including:

-Transmission has a direct impact on the cost and timeline for accessing resource options evaluated in generation planning;

-The need for transmission is affected by generation retirements and the type and location of planned generation resources; and

-As discussed in the next section, expanding transmission ties to neighboring grid operators can also offer a lower-cost source of energy and capacity than building in-region resources.

Q. WHAT ARE UTILITY BEST PRACTICES FOR COORDINATING GENERATION AND TRANSMISSION PLANNING?

A. There are multiple examples of utilities successfully incorporating proactive multi-value transmission planning into their IRPs to achieve co-optimized or at least iterative generation and transmission planning. For example, Arizona utility Salt River Project ("SRP") has moved to an Integrated System Plan that attempts to minimize the total cost to ratepayers of generation plus transmission and distribution, consistent with the principles described above and below. Because precise generator locations are not known, SRP explores different scenarios for generation additions and their locations, and assesses the impact of adding those resources on transmission constraints.[74] SRP then models the transmission expansion that will be required under each scenario, and identifies the lowest-cost solutions. SRP indicates it intends to "Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth"[75] based on those results, with a particular focus on proactively identifying higher-voltage transmission expansion that takes longer to plan, permit, and build.

[74] Salt River Project, *2023 Integrated System Plan*, https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/grid-management/isp/SRP-2023-Integrated-System-Plan-Report.pdf, at 12-14, 84-92, 115-118.

[75] *Id.*, at 14.

Xcel's utility subsidiary Public Service Company of Colorado uses similar methods to conduct integrated transmission and generation planning in its IRP, which is called an Electric Resource Plan ("ERP"). Xcel notes that "following the Company's 2016 ERP, Public Service's Transmission Planning and Resource Planning groups have been actively collaborating on how to better align their respective processes for future ERPs. One of the outcomes of those efforts has been attempting earlier identification of the anticipated size and location of potential generation resources needed to meet public policy initiatives, so that Public Service's transmission planners can help identify the transmission necessary to reliably accommodate new resources."[76]

This process resulted in Xcel's ERP successfully proposing a looped double-circuit 345-kV transmission expansion from the Denver area into eastern Colorado, called the Pathway Project. In the ERP, Xcel describes the iterative process through which the proactive transmission plan precedes the selection of specific interconnecting generators through an economic bidding process: "Generation facilities that will ultimately interconnect to the Pathway Project will largely be driven by the competitive Phase II resource solicitation that will occur in this Proceeding. However, the proposed location and route of the line is strongly influenced by the location of developer bids received in previous ERPs."[77] Xcel also explains that it accounts for direct interconnection costs in reviewing bids, but not network upgrades as those are shared among many generators and provide multiple benefits: "Transmission network upgrade costs are not factored into bid comparisons as these costs address the cumulative system impact of the aggregate bids comprising the Preferred Plan and do not affect individual bid pricing."[78] The initial transmission

[76] Hari Singh, *Direct Testimony and Attachments of Hari Singh,* (March 2021) https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Clean%20Energy%20Plan/HE_107_-Direct_Testimony-Hari_Singh.pdf, at 19.

[77] *Id.*,at 27.

[78] Xcel Energy, *2021 ERP, Appendix Q: Phase II Transmission Report*, (September 2023) https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/PUBLIC%20Appendix%20Q%20-

expansion was proposed with the expectation that those plans would be refined in response to generation bids received in Phase II.

PacifiCorp has successfully integrated generation and transmission planning in its IRP. This resulted in the Energy Gateway project, including Gateway South and Gateway West, which are now nearing completion. PacifiCorp explains why it transitioned to this proactive approach: "Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development."[79] As with Xcel Colorado, that initial plan has been iteratively refined over time in response to changes in interest from generation developers and others.

Q. IN ADDITION TO UTILIZING PROACTIVE MULTI-VALUE TRANSMISSION PLANNING, CAN GEORGIA POWER ALSO RELY ON THE INTERCONNECTION QUEUE?

A. The current interconnection queue can be a useful input for transmission planning, by identifying areas where developers are interested in building generation projects, but it should not be the only input. The location of proposed projects in the queue is heavily shaped by where there is currently available transmission capacity, and new transmission build will change the topology of the system and create new unconstrained entry points for renewables. As a result, Georgia Power should also proactively plan transmission to new

%20Transmission%20Report.pdf, at 23.

[79] Pacificorp, *2023 Integrated Resource Plan: Volume I*, (March 2023) https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf, at 100.

areas that are promising for low-cost renewable development. One way to do that is by using the results of a "Request for Proposals" or other solicitation to get market cost data from proposed generators in different locations. Georgia Power's renewable energy solicitations can serve as an important source of that cost information. Then, Georgia Power can determine the cost of potential grid upgrade portfolios to accommodate groups of those projects, and choose the grid upgrades that minimize the total generation plus transmission cost.

This type of synchronized generation plus transmission planning is necessary to truly achieve "integrated" resource planning. Because transmission upgrades work together to enable the efficient and reliable flow of power across the network, Georgia Power should plan and evaluate a holistic portfolio of upgrades rather than its current approach of evaluating single projects to address a single problem. Planning should also account for the economies of scale from higher-voltage and double-circuit transmission to right-size for the long-term need.

Q. WHAT TYPE OF TRANSMISSION PLANNING SHOULD THE COMMISSION REQUIRE GEORGIA POWER TO IMPLEMENT?

A. My recommendation is that the Commission should direct Georgia Power to conduct a synchronized generation and transmission planning process that attempts to minimize total costs for generation plus transmission to meet long-term needs, using proactive multi-value transmission planning to plan upgrades that maximize transmission's net benefits. FERC Order 1920 now requires planners to adopt proactive multi-value transmission planning, including modeling at least three scenarios over a 20-year planning horizon and accounting for the seven transmission benefits discussed above[80] to ensure that the rates paid by customers are just and reasonable. As discussed in more detail in the next section, Order 1920 can serve as an impetus for Georgia Power to revise its planning methods and also

[80] FERC, *Order 1920*, https://www.ferc.gov/news-events/news/presentation-order-no-1920-building-future-through-electric-regional-transmission

push for more effective transmission planning and cost allocation methods across the Southeast.

MISO and others have successfully used a synchronized generation and transmission planning approach to minimize total costs to ratepayers. As illustrated in the following chart from the MISO planning document that led to the MVPs, synchronized planning minimizes the total cost to ratepayers of generation plus transmission by building the optimal amount of transmission.[81]

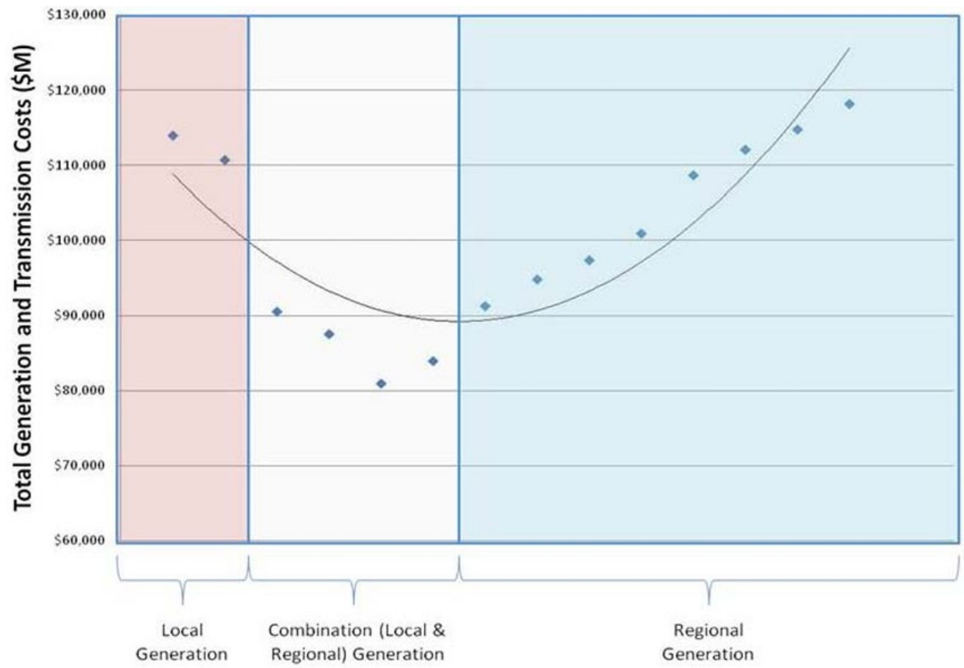

Figure 1: MISO chart showing how co-optimized generation and transmission planning minimizes cost for ratepayers

While planning and building longer-term transmission solutions can take time, Georgia Power can use the interim solutions discussed above, like battery storage, demand response, and grid-enhancing technologies, to meet near-term needs.

[81] Midwest Indep. Sys. Operator, *Regional Generation Outlet Study*, 3 (Nov. 19, 2010), https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.

IV. GEORGIA POWER SHOULD EVALUATE THE NET BENEFITS OF EXPANDING TIES WITH NEIGHBORING UTILITIES

Q. CAN GEORGIA RATEPAYERS ALSO BENEFIT FROM PROACTIVE MULTI-VALUE TRANSMISSION PLANNING OF TRANSMISSION TIES WITH NEIGHBORING UTILITIES?

A. Yes. The benefits of proactive multi-value transmission planning described above also apply to expanding ties to neighbors. In fact, the benefits from multi-value planning may be even larger because ties provide a larger set of economic, reliability, and resilience benefits, including reducing the amount of generating capacity or reserve margin needed to achieve a target level of reliability.

Q. DOES GEORGIA POWER CURRENTLY USE PROACTIVE MULTI-VALUE PLANNING TO EVALUATE EXPANDING TRANSMISSION TIES WITH NEIGHBORS?

A. No. Georgia Power indicates its primary mechanism for coordinating with neighbors is through affected system studies.[82] Affected system studies are studies triggered in reaction to planned upgrades or interconnections on Georgia Power's system, and only assess whether those changes cause reliability concerns on neighboring systems that trigger a need for upgrades on those systems. As a result, affected system studies represent the bare minimum for coordination with neighbors, and are neither proactive nor multivalue.

Affected system studies are also inefficient as they are typically conducted at the final stages of the interconnection study process. These studies can result in large upgrade costs being allocated to those generators, which can cause them to drop out, which in turn can shift upgrade costs to other generators through the restudy processes, causing cascading uncertainty and costs to projects throughout the queue. Using proactive transmission planning and shared cost allocation to build needed transmission near the seam can benefit both neighboring grid operators by alleviating the reliance on affected system studies to

[82] Georgia Power response to STF-GS-1-7b

plan and pay for those upgrades. This was the primary impetus for the Joint Targeted Interconnection Queue projects that MISO and SPP are developing, as discussed in more detail below.[83] This would benefit Georgia Power by reducing the interconnection cost and uncertainty associated with generators and loads in its queue, as well as the cost of affected system upgrades triggered by its planned transmission investments.

When asked in discovery, Georgia Power also takes a very narrow view of what should be assessed when evaluating if expanding transmission ties with neighbors is prudent. Georgia Power answers that "Additions to transfer capability become prudent if existing firm commitments for delivery service and reliability margins (Transmission Reliability Margin ("TRM") and Capacity Benefit Margin ("CBM") cannot be met. Additions to transfer capability are also prudent for Transmission Service Requests on OASIS that require additional capability to accommodate the requested delivery for imports from or exports to other Balancing Authority Areas."[84] As explained above and below, expanding transmission ties provides a wide range of economic, reliability, and resilience benefits for Georgia ratepayers, and only a small share of those are encompassed within Georgia Power's measure of prudent expansion. Moreover, Georgia Power's answer only envisions an expansion of ties in reaction to firm transmission service requests that cannot be accommodated, with no mechanism for proactive expansion that is net beneficial for ratepayers.

Q. ARE THERE OPPORTUNITIES FOR THE COMMISSION AND GEORGIA POWER TO MOVE THE REGION TO MORE EFFICIENT TRANSMISSION PLANNING AND COST ALLOCATION PROCEDURES?

[83] SPP and MISO, *SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes* (December, 2022), available at: https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf.

[84] Georgia Power response to STF-GS-1-3a

A. Yes. The time is particularly ripe as FERC Order 1920 requires development of new regional transmission planning and cost allocation methods by next year. Georgia Power and the Commission can work with other utilities and state regulators through Southeastern Regional Transmission Planning ("SERTP") to develop workable regional transmission planning and cost allocation mechanisms.

Q. DO SOUTHEASTERN REGIONAL TRANSMISSION PLANNING ("SERTP") PROCESSES CURRENTLY USE MULTI-VALUE PLANNING?

A. No. Similar to Georgia Power's transmission planning methods, the SERTP processes greatly understate the benefits of transmission by only accounting for the benefit of deferring transmission upgrades needed to meet NERC reliability criteria. SERTP also uses siloed instead of multi-value transmission planning, with separate processes for evaluating reliability, economic, and public policy projects.[85] As a result, SERTP has not seen substantial transmission projects move forward during recent planning cycles.

Q. HAVE THERE BEEN CONSEQUENCES FROM SERTP NOT USING PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. Yes. The SERTP region trails other regions in transmission expansion, falling well short of the level of investment other regions have found maximizes net benefits for ratepayers. The U.S. Department of Energy's Transmission Needs Study found that the Southeast has greatly lagged other regions in building new transmission, building only 110 circuit miles per year on average over the period 2011-2020. This is less than one-quarter of the national rate on a load-weighted basis, with the Southeast building .21 miles/TWh of load versus a national average of .88 miles/TWh.[86] Similarly, Americans for a Clean Energy Grid

[85] See the separate submission forms for economic and public policy study requests at SERTP, *Reference Library: Forms*, *available at* http://www.southeasternrtp.com/reference_library.cshtml

[86] U.S. Department of Energy, *National Transmission Needs Study*, (December 2023), *available at* https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf, at 22

recently released a report card scoring regions based on their transmission planning methods and their success in building transmission. The Southeast was the only region in the country to receive an "F" grade, and the only region that failed to build any transmission lines at or above 300-kV during the period 2020-2022.[87] Transmission expansion is essential for efficiently addressing load growth, changes in the generation mix, and reliability risks from severe weather. Continuing to rely on siloed and reactive processes that understate the benefits of transmission harms ratepayers by depriving them of affordable and reliable power.

Q. SHOULD OPPORTUNITIES FOR EXPANDING TIES WITH NEIGHBORING UTILITIES BE EVALUATED IN GEORGIA POWER'S IRP?

A. Yes. Because ties can access low-cost generation and provide capacity value, they should be economically compared against other potential sources of energy and capacity in integrated resource planning. Given the long lead time required to develop new transmission ties, particularly with neighboring grid operators, a long-term planning process like an Integrated Resource Plan is the appropriate forum to assess their value. Methods used to account for the resource adequacy contributions of generators, like the Effective Load Carrying Capability method used in Georgia Power's IRP, can also be applied to transmission ties.[88] The Reserve Margin Study included in the IRP used that method to evaluate diversity in net load and generator outage patterns between Southern Company and neighboring utilities. The same tool and data could be used to calculate the capacity value benefits of expanding ties with different neighboring grid operators.

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[87] *See* Zimmerman, et al., *Transmission Planning and Development Regional Report Card*, AM. FOR A CLEAN ENERGY GRID (June 2023).

[88] D. Stenclik, *Transmission as a Capacity Resource*, (April 2025) https://www.telos.energy/post/transmission-as-a-capacity-resource

Other utilities have economically evaluated tie expansions as part of an IRP. Portland General Electric's most recent IRP selected transmission to access Wyoming wind and Desert Southwest solar as part of the economically optimal portfolio. PGE also included the capacity value benefit this transmission expansion provides due to net load diversity with those other regions.[89] Xcel Colorado modeled the economic value of a tie with PacifiCorp in its integrated resource planning process,[90] while Idaho Power has successfully planned multiple large transmission tie lines with neighbors.[91] PacifiCorp's IRP includes impacts of planned transmission on its import and export transfer capacity.[92] In Nevada, NV Energy included the benefit of expanded import and export capability in evaluating Greenlink Nevada.[93]

Q. ARE THERE EXAMPLES OF TIES BETWEEN GEORGIA POWER AND NEIGHBORING UTILITIES THAT COULD POTENTIALLY BE BENEFICIALLY EXPANDED?

A. Yes. While my primary recommendation is for the Company, likely in conjunction with other utilities in the region, to conduct the detailed transmission planning and engineering studies necessary to determine the optimal expansion solutions, the following is a non-

[89] Portland General Electric, *Clean Energy Plan and Integrated Resource Plan 2023*, https://assets.ctfassets.net/416ywc1laqmd/7gZv7ENSucpUszs63bDQG6/aaae6d2a430e97189edcc836cd2a604e/2023_CEP-IRP_Ch_09.pdf, at 227-229.

[90] Xcel Energy, *2021 ERP, Appendix Q: Phase II Transmission Report*, (September 2023) https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/PUBLIC%20Appendix%20Q%20-%20Transmission%20Report.pdf

[91] Idaho Power, *Integrated Resource Plan*, (September 2023) https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-irp-final.pdf, at 83-98.

[92] Pacificorp, *2023 Integrated Resource Plan: Volume I*, (March 2023) https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf

[93] NV Energy, *PUCN Approves NV Energy's Greenlink Nevada Transmission and Renewable Energy Initiative*, (March 2021) https://www.nvenergy.com/about-nvenergy/news/news-releases/pucn-approves-nv-energys-greenlink-nevada-transmission-and-renewable-energy-initiative

exhaustive list of illustrative examples of the type of potential upgrades that should be evaluated for feasibility and economic net benefits.

-Expanded ties with South Carolina: Georgia Power's proposal to install a new 35-mile 230 kV line between Hartwell Energy and Middle Fork,[94] while valuable, could potentially be more net beneficial if it were built at 500 kV. In response to discovery, Georgia Power confirms that it did not evaluate any alternatives to the proposed 230 kV solution.[95] Per Table 1 above, typical 500 kV lines can carry about 4 times as much power, or around 2,000 MW more, than 230 kV lines. A 500 kV line could capitalize on Georgia Power's plan to install 500 kV equipment at Middle Fork as part of other proposed projects. If built in partnership with Duke in South Carolina, the 500 kV line could extend past Hartwell Energy to the Anderson substation where multiple 230 kV lines currently interconnect, ensuring sufficient transfer capacity to handle increased flows on the South Carolina side of the border.

Georgia Power could also evaluate opportunities to expand ties with Dominion Energy South Carolina in the Augusta and Plant McIntosh areas, as current ties between the utilities are undersized relative to the transmission capacity on the Georgia Power and Dominion systems in those areas.

-Expanded ties with the Tennessee Valley Authority ("TVA"): The existing 230 kV line from the Rock Spring substation in Georgia to TVA's Widows Creek substation could be upsized by adding a second 230 kV circuit, or ideally rebuilt at 500 kV. Georgia Power's response to STF-GS-2-20(a) confirms that none of the transmission projects proposed in the Ten Year Transmission Plan increase transfer capacity with TVA.

-Expanded ties with Florida utilities: Georgia Power proposes rebuilding and reconductoring multiple 115 kV lines in the Bainbridge area in south Georgia,[96] including

[94] Georgia Power IRP Appendix 3, 2024 GA ITS Ten-Year Plan (2025-2034), page 59

[95] Georgia Power response to STF-GS-2-7, Attachment Public Disclosure (Northeast Corridor Study Report)

[96] Georgia Power IRP Appendix 3, 2024 GA ITS Ten-Year Plan (2025-2034), at 229

reconductoring a 115 kV tie to Florida Power and Light's Sinai substation.[97] Georgia Power should evaluate the feasibility and net benefits of rebuilding these lines at 230 kV. At minimum, Georgia Power should consider building the lines with the capability to later convert them from 115 kV to 230 kV operation. As discussed above, investing in this type of optionality for later expansion can be valuable relative to an undersized solution that may need to be prematurely replaced.

Q. HAVE OTHER STUDIES ASSESSED OPTIMAL TRANSMISSION EXPANSION IN THE SOUTHEAST?

A. Yes. As shown below, NERC's Interregional Transfer Capability Study recommended large transmission expansion similar to the upgrades proposed above. Specifically, it recommended increasing transfer capacity from Southern Company to Florida by 1,200 MW, with the Carolinas by 2,200 MW, and with MISO South by 300 MW, as prudent additions to address resource adequacy concerns in those neighboring regions.[98] While Southern Company was lucky enough to avoid a generation shortfall in the 12 weather years modeled in NERC's study, this does not indicate future severe weather events will spare Georgia. Regardless, Georgia Power ratepayers would benefit from these expanded ties reducing the amount of generating capacity investment needed to maintain resource adequacy in Georgia. Expanded ties also benefit Southern Company ratepayers through reduced production costs by enabling expanded imports of lower-cost power from neighbors when it is available, and expanded profits from exports when Georgia's supply is greater than its demand. Because the neighbor utilities would also receive reliability and economic benefits these lines, they and their regulators should have an interest in partnering on the planning and cost allocation for these lines.

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[97] *Id.*, at 195

[98] NERC, *Interregional Transfer Capability Study* https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/ITCS_Filing_Fall2024_signed.pdf, at xvi, 98

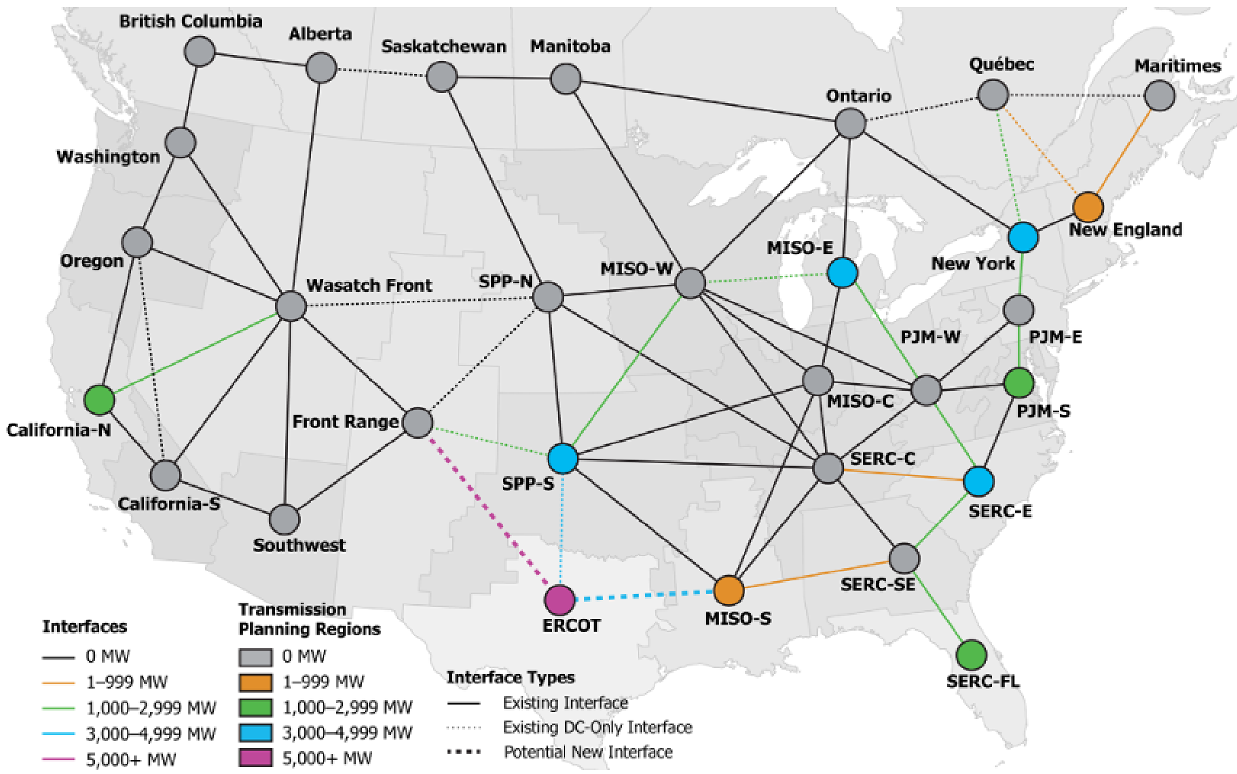

Figure 1: Prudent transmission addition in NERC Interregional Transfer Capability Study

The DOE's National Transmission Planning Study identified upgrades similar to those discussed above in its economically optimal transmission expansion, as shown in the map below.[99] In the Alternating Current optimized expansion, the study added one new 500 kV tie to South Carolina, three new 500 kV ties to TVA, and a new 500 kV tie to MISO South following existing transmission right-of-way, as well as a new 500 kV tie to Florida.

[99] DOE, *National Transmission Planning Study: Executive Summary*, (October 2024) https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-ExecutiveSummary.pdf, at 23.

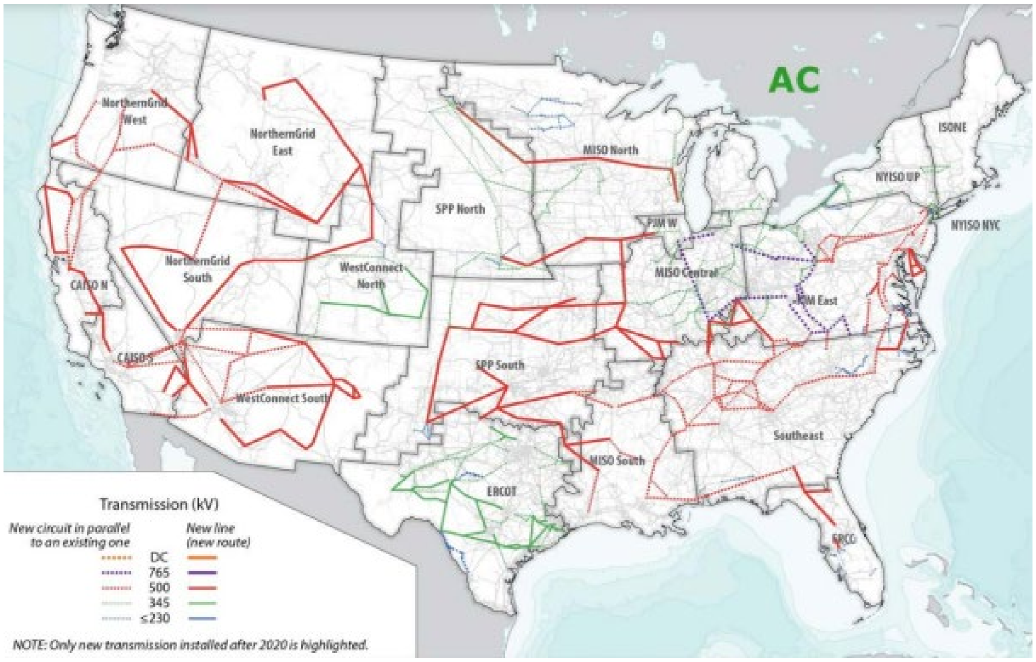

Figure 2: Optimal AC transmission expansion in National Transmission Planning Study

Q. HOW DO EXPANDED TIES PROVIDE ECONOMIC, RELIABILITY, AND RESILIENCE BENEFITS?

A. Expanding transmission ties to neighboring grid operators can significantly improve reliability and reduce cost. Expanded ties could not only deliver lower-cost energy when neighbor utilities have a lower marginal production cost than Georgia Power, but also offer the Company dependable capacity because of diversity in the timing of peak demand, renewable output, and conventional generator outages between the Company and neighboring regions.[100] Utilities experience peak demand and generator outages at different times, and tapping into this diversity significantly reduces the planning reserve margin that is needed to maintain the same level of reliability.[101] That diversity also increases resilience

[100] M. Goggin *et al.*, *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 4.

[101] For example, MISO finds around $3.2 billion in annual benefits because "MISO's large geographic footprint allows members to lower planning reserve margins (PRM), ultimately reducing the amount of required installed capacity. Much of the value MISO creates comes from the value of sharing capacity across MISO's large geographic footprint—

during extreme weather events, as extreme weather systems move over time and tend to be at their most severe in relatively small geographic areas.[102] For example, Florida had abundant generating supplies during Southern Company's time of peak need during Winter Storm Elliott in December 2022.[103]

Given regional weather and climate diversity and the expansive footprints of Southern Company's neighbors, at least one neighboring power system is likely to have available capacity during Southern Company's times of peak need. A stronger regional grid allows all utilities to share in those resilience benefits and maintain the same level of reliability with a lower reserve margin.

Southern Company's planned solar additions further increase the value of expanding these ties. Expanding ties will allow the Company to export solar during the day and summer to avoid backing down inflexible conventional generators, and import other energy resources, including wind, at night and during the winter.[104] Multiple studies have confirmed that

by setting requirements for a system peak instead of each balancing authority keeping reserves for their own region. Savings are generated because MISO members do not need as much capacity for the same level of reliability." MISO, *MISO Value Proposition Annual View, 2023 Overview* (March 2024), at 6, available at https://cdn.misoenergy.org/2023%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report%20Final632082.pdf?v=20240306103856. Similarly, PJM finds $1.2-1.8 billion in annual savings because "There is considerable diversity in electrical use patterns in the large PJM footprint; not all areas peak at the same time of the year. As a result, resources in one area of the system are available to help serve other areas at peak times, and a smaller reserve is required. In addition, the large and varied resource fleet across the entire PJM region spreads the generator outage risk across a larger collection of generators, improving reliability." PJM, *PJM Value Proposition*, at 2, available at: https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx.

[102] M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, (July 2021) https://www.cleanenergygrid.org/wp-content/uploads/2021/09/GS_Resilient-Transmission_proof.pdf; M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott*, (February 2023) https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.

[103] M. Goggin *et al., Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 4.

[104] Americans for a Clean Energy Grid, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.* (October 2020), https://cleanenergygrid.org/wp-

expanding transmission ties within and among grid operators to access that diversity is essential for cost-effectively achieving very high renewable penetrations.[105] Geographically diverse renewables, as well as a more diverse portfolio of solar and wind, provide more dependable capacity and less variable output because their output profiles are weakly or negatively correlated.

Electricity supply and demand are becoming more weather-dependent for other reasons as well, increasing the value of ties to access weather diversity. As noted above and discussed in more detail below, thermal generators and particularly gas generators experience correlated outages during extreme cold and, to a lesser extent, extreme heat. Because these extreme weather events are at their most severe in relatively small geographic areas, expanding ties with neighbors is a highly effective strategy for hedging this risk. Electricity demand is also becoming more weather-dependent with electrification of building and water heating.

V. IN IRP RESOURCE SELECTION MODELING, GEORGIA POWER SHOULD REDUCE THE CAPACITY ACCREDITATION OF THERMAL GENERATORS TO ACCOUNT FOR CORRELATED OUTAGES

Q. IN THE ECONOMIC SELECTION OF GENERATORS, DOES GEORGIA POWER'S IRP ACCOUNT FOR CORRELATED OUTAGES OF THERMAL GENERATORS?

A. No. While correlated outages of thermal generators were accounted for in the Reserve

content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf, at 21-22.

[105] *See, e.g.*, Patrick Brown and Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule 5(1), (January 2021) https://www.sciencedirect.com/science/article/pii/S2542435120305572; NREL, *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study* (September 2021) https://ieeexplore.ieee.org/document/9548789; MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on US CO2 Emissions*, Nature Climate Change, 526–531 (2016) https://www.nature.com/articles/nclimate2921, at 6.

Margin study, they were not factored into the economic selection of resources. As the Company explains in response to discovery in this docket, "Incremental cold weather forced outages were not factored into the capacity accreditation for the generating resources chosen during expansion modeling because it is a weather-normal analysis, and the impact of generator outages is accounted for in the reserve margin requirement included in the capacity expansion modeling."[106]

As explained below, assigning the capacity accreditation impact of correlated outages to the resources that cause them in the economic selection of generators is more efficient than socializing those costs through a higher reserve margin. Accounting for correlated outages with a lower capacity value accreditation instead of a higher reserve margin should not change Georgia Power's claimed need for capacity, as each MW in reduced accreditation should reduce the need for planning reserves by one MW. Georgia Power should move to this approach in the next IRP and in any evaluation of generation resources through a Request for Proposals or other procurement, as it is essential for selecting an economically optimal generation mix. The data inputs and probabilistic methods used in the Reserve Margin study can be readily used to account for expected correlated outages in the capacity value accreditation of each resource or resource type.

Q. ARE CORRELATED OUTAGES OF THERMAL GENERATORS COMMON?

A. Yes. Correlated outages of gas have occurred across many recent events, including some like Winter Storms Uri and Elliott that resulted in loss of load. FERC and NERC have documented that 55% of the unavailable generating capacity during Winter Storm Uri was gas, with coal capacity contributing another 18%.[107] Similarly, gas accounted for 63% of

[106] Georgia Power response to STF-GS-1-19

[107] FERC, NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States*, available at https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16

unplanned outages and derates during Winter Storm Elliott[108] and 55% during the 2014 Polar Vortex,[109] while coal accounted for a large share of the remainder. Correlated outages and derates of gas generators have also played a major role in reliability concerns during extreme heat, including the 2022[110] and 2020[111] heat waves in California.

Q. HAVE STUDIES QUANTIFIED THE IMPACT OF THERMAL GENERATOR CORRELATED OUTAGES?

A. Recent analysis of Dominion's portion of PJM, conducted by Georgia Power consultant Astrape, shows that accounting for these correlated generator outages significantly reduces the calculated reliability contributions of thermal generating resources. Specifically, Astrape found that accounting for correlated outages can cause an additional 10% reduction in gas resources' capacity contributions during the summer, and 20% in the winter, beyond the forced outage rate that is typically assumed.[112]

PJM recently revised its capacity value accreditation to reflect the risk of correlated outages, and the average capacity value assigned to gas generators declined significantly, dropping to 79% for gas combined cycle generators and 61% for gas combustion turbines

[108] FERC and NERC, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations* (Sep. 21, 2023), at 5, available at: https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[109] NERC, *Polar Vortex Review* (Sept. 2014), at 13, available at: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[110] Regenerate California, *California's Underperforming Gas Plants*: *How Extreme Heat Exposes California's Flawed Plan for Energy Reliability* (July 2023), available at: https://caleja.org/wp-content/uploads/2023/06/2023-Regenerate-Heat-Wave-Report.pdf.

[111] CAISO, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, (Jan. 2021), available at: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[112] Dison et al., Astrapé Consulting, *Accrediting Resource Adequacy Value to Thermal Generation* (Mar. 30, 2022), at 6, Table ES1, available at: https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf (calculated by taking the difference between the 95% accreditation under current methods, and what the study found as the actual summer credit of 84.7% and winter credit of 76.1%).

for planning year 2026/2027.[113] While effective generator weatherization may reduce correlated outages and thus their impact on capacity value accreditation, they cannot fully protect against equipment outages and do not protect against failures due to constrained gas supply or pipeline capacity.

Another study co-authored by NERC used NERC data[114] to demonstrate that conventional generators experience common mode correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events. As shown below, in the SERC region that includes Georgia, actual outages are much greater than expected if outages were uncorrelated events, with about 15-20 GW more concurrent outages than expected.[115]

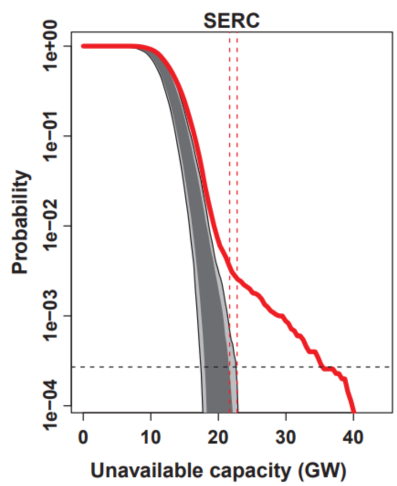

Figure 3: Actual winter generation outages in SERC (red line) are roughly twice the level of outages that would be expected under the assumption that generator outages are uncorrelated independent events (gray area)

[113] PJM, *Preliminary ELCC Class Ratings for Period 2026/27 through 2034/35* (Jun. 4, 2024), at 5, 11, available at: https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20240604/20240604-item-07---preliminary-elcc-class-rating-update.ashx.

[114] Murphy et al., *Resource adequacy risks to the bulk power system in North America*, Applied Energy 212 (Feb. 2018), at 1360, 1372, available at: https://www.sciencedirect.com/science/article/pii/S0306261917318202.

[115] *Id.* at 1366, Fig. 4.

Q. HOW DOES THE FAILURE TO ACCOUNT FOR THESE OUTAGES IN THE IRP'S ECONOMIC OPTIMIZATION AFFECT THE SELECTED RESOURCE MIX?

A. It results in an economically sub-optimal resource mix that is biased towards thermal resources and against renewable and storage resources. Georgia Power's IRP uses an ELCC method to account for how correlations in the output of multiple solar plants or multiple battery resources reduces their capacity contribution as their penetration increases. The same method could and should be used to reduce the accredited capacity contribution of thermal resources, but instead Georgia Power accommodates thermal generators' underperformance through a higher reserve margin.[116] This creates an unlevel playing field between thermal resources and renewable and storage resources.

Adding renewable and storage generation that is not affected by fuel delivery and other constraints reduces risk and increases resilience by diversifying the generation mix. As discussed above, expanding transmission ties to neighboring power systems also reduces this risk by accessing diversity in net load as well as in thermal generator outages, particularly during extreme weather events.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[116] Georgia Power response to STF-GS-1-19: "the impact of generator outages is accounted for in the reserve margin requirement included in the capacity expansion modeling"

Exhibit MG-1: Michael S. Goggin Background and Qualifications

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis “Is it Time for a Change? Science, Policy, and Climate Change”

Experience:

Grid Strategies Vice President February 2018-present

- Serve as a consultant on electricity transmission, grid integration, reliability, market, and public policy issues for consumer, grid operator, non-profit, and industry clients
- Have testified before FERC and in over 25 state regulatory commission cases

AWEA Senior Director of Research, other titles February 2008-February 2018

- Led team responsible for all American Wind Energy Association (now American Clean Power Association) analysis
- Served as primary technical and economic expert for market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (ISO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases)
- Directed economic and power sector modeling to inform AWEA’s policy strategy and support advocacy positions

- Communicated with the press and policy makers about wind energy
- Authored reports to promote AWEA's policy agenda, rebut misconceptions about wind energy, and explain complex energy topics to lay audiences
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. Research Analyst October 2005-February 2008
- Conducted economic analyses of solar, wind, geothermal, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE's renewable energy R&D funding decisions

Union of Concerned Scientists Clean Energy Intern May 2005-October 2005
- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups Policy Analyst August 2004-May 2005
- Analyzed and advocated for clean energy policies at the state and federal level

Exhibit MG-2: Georgia Power's response to data request STF-GS-1-1 in the 2023 IRP Update (Docket No. 55378)

STF-GS-1-1
Question:
Has the Company evaluated the use of Battery Energy Storage Systems (BESS) to reduce, defer, or eliminate the need for the transmission upgrades identified in the Updated IRP? If so, please provide that evaluation and explain why BESS were not selected. If the Company has not conducted that evaluation, please explain why not.

Response:

Please refer to the Company's response to STF-DEA-4-15.

The Company did not study Battery Energy Storage Systems ("BESS") as options to reduce, defer, or eliminate the transmission upgrades identified in the 2023 IRP Update to facilitate the delivery of power from the proposed Plant Yates combustion turbines.

Exhibit MG-3: Georgia Power's response to data request STF-GDS-4-7.e. in the 2022 IRP (Docket No. 44160)

e. Alternative solutions such as energy storage or distributed energy resources have not been considered yet for various reasons. Some projects such as the Klondike switch replacement, are relatively inexpensive and easy to accomplish, so no such alternative is needed. For the identified strategic projects (second Heard County – Tenaska 500 kV line and the new Lagrange – North Opelika 230 kV line), the magnitude of storage or DER that would be needed makes those options untenable. The solutions for the other identified constraints are still under review. Other strategic solutions may replace some of the listed projects, and energy storage, DER, and operating guides will be considered in due time, before the listed projects are approved and budgeted.

Exhibit MG-4: Georgia Power's responses to data requests STF-GS-1-8 and STF-GS-1-9 in the 2023 IRP Update (Docket No. 55378)

STF-GS-1-8

<u>Question:</u>

As a follow-up to the STF-JKA-4-5 question about discussing non-firm, interruptible, or lower service quality options with new customers, has the Company evaluated demand response programs that would compensate those customers for curtailing their load, particularly during the generation or transmission system contingency events that triggered a need for upgrades in the Transmission Screening Analysis? If so, please discuss that evaluation. If not, please explain why the Company has not conducted that analysis.

<u>Response:</u>

The Company is proposing a new Curtailable Load program, which will compensate customers for curtailing load during periods of extreme supply and demand conditions. The customer payment will be directly linked to the capacity value provided by the potential demand reduction.

STF-GS-1-9

<u>Question:</u>

As a follow-up to the STF-JKA-4-5 question about evaluating non-firm, interruptible, or lower service quality options with new customers, has the Company spoken with new customers about an option for potential reductions in interconnection costs or rates from deploying customer-sited battery storage or demand response resources? If so, please describe those discussions. If not, please explain why the Company has not offered that option.

Response:

Yes, the Company makes potential customers aware of rate options and programs available to them, including the Real Time Pricing rate. The Company also has current demand response programs and is proposing three new DER and DR customer programs as part of this IRP Update to enable both new and existing customers to receive credit for providing system value from customer-sited resources.