BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:

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

DIRECT TESTIMONY AND EXHIBITS

OF

JAMIE BARBER, JOHN KADUK, AND
JEFFREY D. BOWER

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

May 5, 2025

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I. QUALIFICATIONS AND SUMMARY

Q. MS. BARBER, PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jamie Barber, and I am the Director of the Energy Efficiency and Renewable Energy Unit for the Georgia Public Service Commission ("Commission"). My business address is 244 Washington Street SW, Atlanta, GA 30334.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My educational background and work experience are provided in my resume, which is attached as Staff Exhibit_BKB-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in each of the 1998 through 2009 United Cities Gas Company (now known as Atmos Energy Corporation) Gas Supply Plan Proceedings. I also testified in Docket No. 10270, GPSC Determination of Lack of Market Constraints on Atlanta Gas Light Company's Commodity Sales; Docket No. 11114, Rule Nisi Against United Gas Management of Georgia, Inc.; Docket No. 14311, Earnings Review to Establish Just and Reasonable Rates for Atlanta Gas Light Company; Docket No. 15296 Service Quality Standards for Certified Marketers and Regulated Provider; Docket No. 18638-Atlanta Gas Light Company's 2004/2005 Rate Case; Docket No. 20298 Atmos Energy Corporation's

2005 Rate Case; Docket No. 27163 Atmos Energy Corporation's 2008 Rate Case; Docket No. 30442 Atmos Energy's 2010 Rate Case; Docket No. 36498 Georgia Power Company's 2013 Integrated Resource Plan Filing; Docket No. 36499 Georgia Power Company's 2013 Demand Side Program Certification; Docket No. 37854, Georgia Power Company's Application for the Certification of the Power Purchase Agreements for Wind Resources from the Blue Canyon II and Blue Canyon VI Wind Farms; Docket No. 38877, Georgia Power Company's Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements, Docket No. 36989 Georgia Power Company's 2013 Rate Case, Docket No. 40161 Georgia Power Company's 2016 IRP Filing, 40162 Georgia Power Company's 2016 Demand Side Program Certification, Docket No. 41596, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements, Docket No. 41734, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements for the Commercial and Industrial Program, Docket No. 43210 Georgia Power's 2019 IRP Filing, Docket No. 43211 Georgia Power Company's 2019 Application for the Certification, Decertification, and Amended Demand-Side Management Plan, and Docket No. 42516 Georgia Power Company's 2019 Rate Case, Docket No. 44160 Georgia Power Company's 2022 IRP Filing, Docket No. 44161 Georgia Power Company's 2022 Application for the Certification, Decertification, and Amended Demand-Side Management Plan, Docket No. 44280 Georgia Power Company's 2022 Rate

Case, and Docket No. 44880, Georgia Power Company's Application for the Certification of the 2023 Biomass Request for Proposals Power Purchase Agreements.

Q. MR. KADUK, PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is John Kaduk, and I am the Assistant Director of the Energy Efficiency and Renewable Energy Unit for the Commission. My business address is 244 Washington Street SW, Atlanta, GA 30334.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My educational background and work experience are provided in my resume, which is attached as Staff Exhibit_BKB-2.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in Docket No. 31081, Georgia Power Company's 2010 Integrated Resource Plan; Docket No. 36498, Georgia Power Company's 2013 Integrated Resource Plan; Docket No. 38877, Georgia Power Company's Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements; Docket No. 40161, Georgia Power Company's 2016 Integrated Resource Plan; Docket No. 41596, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements; Docket No.

41734, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements for the Commercial and Industrial Program; Docket No. 42310; Georgia Power Company's 2019 Integrated Resource Plan; Docket No. 42625, Georgia Power Company's Application for the Certification of the 2020/2021 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements; Docket Nos. 4822, 16573 and 19279 Georgia Power Company's Avoided Cost Dockets; Docket No. 43814, Georgia Power Company's Application for the Certification of the 2022/2023 Utility Scale Renewable Power Purchase Agreements; Docket No. 55378, Georgia Power Company's 2023 Integrated Resource Plan Update; and Docket No. 44880, Georgia Power Company's Application for the Certification of the 2023 Biomass Request for Proposals Power Purchase Agreements.

Q. MR. BOWER, PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jeffrey D. Bower. I am a Principal Consultant at Daymark Energy Advisors ("Daymark"), which provides energy planning, market analysis, and regulatory policy consulting and advisory services to support decision making within the electricity and natural gas industries. We serve a broad range of clients in North America, including private and public utilities, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, public policy and energy research organizations, and other industry stakeholders. Our technical skills include power market forecasting models and methods, economics, management, resource planning, rates and pricing, and energy procurement and contracting. Our experience includes detailed analyses of energy and environmental performance of the electric systems, economic planning for transmission, and market analytics. My business address is 370 Main Street, Suite 325, Worcester, MA 01608.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My educational background and work experience are provided in my resume, which is attached as Staff Exhibit_BKB-3.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION OR OTHER COMMISSIONS?

A. Yes. Most recently I testified in Docket No. 55378 regarding Georgia Power Company's request for certification of battery energy storage systems ("BESS"). I also testified in Docket Nos. 44160 and 44161 regarding the 2022 Integrated Resource Plan and in Docket Nos. 4822, 16573, and 19279 regarding the application of Georgia Power Company's Renewable Cost Benefit Framework ("RCB Framework") to Public Utility Regulatory Policies Act of 1978 ("PURPA") qualifying facilities ("QFs"). I have also testified before regulatory commissions in other states. In addition, I have supported Commission Staff's evaluation of Georgia Power Company's RCB Framework since 2016.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. We are presenting testimony on behalf of the Commission Public Interest Advocacy Staff ("Staff").

Q. PLEASE PROVIDE THE RECOMMENDATIONS THAT STAFF IS MAKING FOR THE COMMISSION TO CONSIDER.

A. Based on our review of Georgia Power Company's ("Georgia Power" or "Company") filing, testimony, data request responses, and other pertinent information for this case, we have the following recommendations for the Commission's consideration:

1. The Company should consider improvements to the Renewable Integration Study ("RIS") methodology to more accurately reflect the flexibility of the system and its ability to address solar variability.
2. The Company should finalize the next RIS far enough in advance of the 2028 IRP so that the results can be used in the Resource Mix Study.
3. The Company should engage with Staff prior to the next Renewable Request for Proposals ("RFP") to determine how the specific Integration Costs and Flex Credits will be determined using the results of the 2024 RIS.
4. Staff recommends continuing to calculate Renewable Energy Credit ("REC") prices from third-party data and extrapolating that value using a compound annual growth rate calculation. If the Company seeks to change the methodology in the future, it should collaborate with Staff regarding a replacement methodology.
5. Staff recommends approval of the Company's request to replace the Deferred Transmission Investment component of the RCB Framework with a Locational Transmission Value component.
6. Staff recommends updating the Company's expansion modeling of new solar tracking resources to reflect the Company's Effective Load Carrying Capability ("ELCC") calculations.

7. Staff recommends approval of the Company's request to continue the implementation and integration of a Distributed Energy Resource Management System ("DERMS") with the Company's real-time operations platforms. Staff recommends approval of the Company's incremental spending for DERMS for the remainder of 2025 through 2028, which was not already approved by the Commission in the 2022 Rate Case. Staff further recommends that the Company be required to make an annual filing which will provide the current status of the DERMS implementation as well as the amount of budget that has been spent to date.
8. Staff recommends that any unfilled megawatts ("MW") from the current Distributed Generation ("DG") and Utility Scale RFPs roll forward on an ongoing basis to subsequent respective RFPs. Staff is also supportive of any unfilled MW from future DG and Utility Scale renewable RFPs continuing to roll forward on an ongoing basis to subsequent respective RFPs.
9. Staff supports the Company's requested modifications to the utility scale procurement process since changes are necessary to procure enough renewable energy to meet customers' demands. Regarding Flexible Commercial Operation Dates ("CODs"), Staff, the Company, and the IE will need to determine what changes, if any, will be needed to the Utility Scale RFP evaluation.
10. Staff recommends approval of the Company's request to procure 1,000 MW of utility scale renewable projects for all customers and up to an additional 3,000 MW to satisfy customer subscriptions. With the understanding that Staff, the IE, and the Company will resolve any concerns related to the evaluation of bids with flexible CODs, Staff also recommends approval of Georgia Power's request to allow bidders

to provide flexible CODs and the use of a multi-phase approach which would include the procurement of customer identified resources.

11. Staff supports the Company's requested modifications to the DG procurement process. Regarding the proposed request to allow flexible DG resources to participate in future RFPs, Staff is not fully aware how the requirement that the project be visible and controlled through DERMS could impact future flexible DG bid prices. Staff is generally supportive of allowing bidders the option to bid in flexible CODs.

12. Staff recommends approval of the Company's request to procure 100 MW of DG resources, including unfilled MW from the 2024 DG RFP, with or without renewable-charged or grid-charged storage facilities, through two RFPs. Staff also recommends approval of the multi-phase approach, including customer identified resources, to assist in procuring resources needed to meet customer subscription demand.

13. Staff recommends approval of the Company's request to use a locational transmission value in future DG RFP evaluations.

14. Staff recommends approval of the Company's proposed modifications to the Customer-Connected Solar Program ("CCSP").

15. Staff recommends approval of the proposed Customer-Sited Solar Plus Storage Pilot Program, conceptually. There are still items that need further discussion and finalization prior to implementation of the pilot program

16. Staff recommends approval of the proposed enhancements to the Clean and Renewable Energy Subscription ("CARES") Utility Scale Subscription Program.

Staff will review the proposed subscription pricing methodology once filed for Commission approval.

17. Staff supports adding the DG Subscription Community Solar Program as another program option for customers. Staff will review the Company's proposed modifications to the contract energy price when the program documents are filed for Commission approval. Staff further recommends that the Company be required to make quarterly filings which will provide the current level of DG Community Solar Program subscriptions, by month.
18. Staff recommends approval of the Large Customer Owned Resiliency ("LCOR") Program and the proposed term modification for the Distributed Energy Resource ("DER") Customer-Owned ("DCO") Program.
19. Staff recommends that Georgia Power receive an additional sum of $3.00/kilowatt ("kW")-year for its proposed renewable procurements and programs in this IRP as it appropriately balances the interests of the Company and customers.
20. Staff recommends approval of the Company's Electric Transportation Vehicle-to-Everything ("V2X") Pilot Project. Staff further recommends an annual filing which provides the status of the pilot and the budget amount that has been spent to date.

II. EVALUATION OF THE RIS

Q. PLEASE SUMMARIZE THE PURPOSE OF THE RIS.

A. The stated purpose of the RIS is to "determine the integration costs associated with a range of solar penetration scenarios on the Southern Company system" (Technical Appendix Vol.

2, Section 5, p. 6). The Company's methodology simulates the system using a reference case and multiple study cases adding solar and BESS to determine whether the estimated output variability of solar creates conditions where the grid cannot adequately balance supply and demand on a 5-minute basis, conditions referred to in the study as "flexibility violations" (Technical Appendix Vol. 2, Section 5, p. 6). The objective of the study is to quantify the costs of mitigating "flexibility violations."

Major outputs of the study include the calculation of the Integration Cost component used in the RCB Framework, and the calculation of a "Flex Credit" to BESS for helping mitigate "flexibility violations."

Q. WHAT IS THE SIGNIFICANCE OF THE INTEGRATION COST CALCULATED BY THE RIS?

A. The Integration Cost calculated by the RIS has two primary uses by the Company. First, it is used in the Aurora capacity expansion analysis in the IRP as an incremental operating cost of solar resources, which provides a penalty on the resource when determining the optimized buildout portfolio. Second, it is used as a component of the RCB Framework to determine the avoided cost thresholds for renewable resource procurements under the Commission approved "best cost" methodology.

Q. WHAT ARE THE HIGH-LEVEL CONCLUSIONS OF THE RIS?

A. The primary objectives of the RIS study are to quantify the cost of adding incremental operating reserves to address variability of solar resources and quantify the system cost reduction of adding BESS along with the solar resources instead of combustion turbine

("CT") capacity. The Company studied six scenarios of incremental solar capacity: 5,000 MW, 7,500 MW, 10,000 MW, 15,000 MW, 20,000 MW, and 25,000 MW.

The cost of mitigating the flexibility violations identified in the model is converted to a cost per megawatt hour ("MWH") for each solar tranche. The results of the study are reproduced below.

Table 1. Base Case Mitigation Costs

Scenario	Solar MW	Mitigation Cost ($/MWH)
1	7,500	2.29
2	10,000	2.53
3	15,000	2.95
4	20,000	3.27
5	25,000	3.50

(Technical Appendix Vol. 2, Section 5, p. 7)

It is noteworthy that the Company's 5,000 MW of solar scenario did not identify any incremental system cost of managing the variability of that quantity of solar capacity (and thus was excluded from Table 1), indicating that the system had sufficient flexibility to respond to variability (Company Response to STF-PIA-3-24). However, the Company decided to extrapolate the mitigation cost down to assign costs to lower amounts of solar, even without supporting model results (Technical Appendix Vol. 2, Section 5, p. 7). That extrapolation is reproduced below.

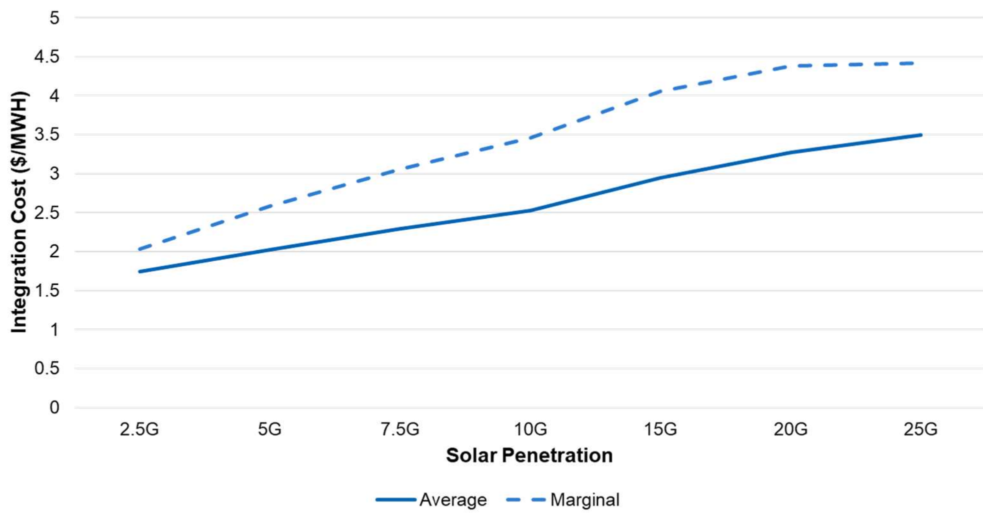

Figure 1. Base Case Integration Costs

(Technical Appendix Vol. 2, Section 5, p. 7)

The study also calculated the value of BESS in reducing the "flexibility violations." The study identified the economic value, termed the "Flex Credit," of an optimized quantity of BESS to completely offset the incremental flexibility violations attributed by the solar resources, summarized in the table below.

Table 2. BESS Breakeven Penetration Levels

Scenario	Solar MW	BESS MW	Flex Credit ($/kW-Yr)
1	7,500	1,500	25.72
2	10,000	1,700	33.48
3	15,000	2,200	45.24
4	20,000	2,500	58.93
5	25,000	2,600	75.77

(Technical Appendix Vol. 2, Section 5, p. 8)

Lastly, the Company used the results of multiple SERVM cases conducted in the study to develop a tool to estimate the Integration Cost for incremental solar and Flex Credit for incremental BESS resources for a system with any combination of existing solar and BESS (Technical Appendix Vol. 2, Section 5, pp. 28-29). According to the Company, this allows for future calculations of these values as additional resources are added to the system without the need to re-run the model.

Q. HAS THE COMPANY MADE CHANGES TO THE RIS METHODOLOGY SINCE THE 2022 IRP?

A. Yes. While many elements of the structure of the Company's analysis are consistent with the prior study, the Company changed several key assumptions and modified the study so that it is more focused on identifying the value of BESS.

Q. WHAT WAS THE CONCLUSION OF STAFF'S REVIEW OF THE RIS IN THE 2022 IRP?

A. During the 2022 IRP, Staff raised several issues regarding the study methodology and results (Docket No. 44160, Direct Testimony and Exhibits of Jamie Barber, Timothy Cook and Jeffrey D. Bower, May 6, 2022, pp. 18-27). As part of the approved stipulation, the Company agreed to use a stipulated value for the Integration Cost component and meet with Staff after the IRP proceeding concluded to discuss Staff's remaining concerns with the methodology (Docket No. 44160, Order Adopting Stipulation, July 29, 2022, p. 28). During the subsequent meeting, the Company presented some information about specific instances when commitment of additional resources was required to manage solar variability (Docket No. 44160, Compliance Filing, June 1, 2023, p. 4). However, this additional information was considered by Staff to be only a first step in providing evidence that the cost of actual solar variability is comparable to the costs calculated in the RIS (Id.).

Q. HAS THE COMPANY PROVIDED ANY ADDITIONAL EVIDENCE IN THE 2025 IRP TO BENCHMARK INTEGRATION COSTS FROM ITS MODELING TO ACTUAL SYSTEM COSTS?

A. No, it has not. The Company has stated that it "has not identified an analysis that can be performed to adequately isolate historical solar variability costs within a dynamic electric system…" (Company Response to STF-PIA-3-44).

Q. DO YOU HAVE ANY CONCERNS WITH RIS AND THE CALCULATION OF THE INTEGRATION COST?

A. Yes. Staff's concerns fall into three categories. First on a fundamental level, Staff does not agree that these extra cost penalties should be assigned solely to solar resources based on their operational characteristics, when solar capacity is selected as part of the Company's least-cost resource planning process.

Second, the RIS is essentially a theoretical exercise, and the model methodology is not designed to quantify a specific cost actually incurred on Georgia Power's system. The study methodology contains multiple shortcomings and flaws which overstate the cost incurred by the system to manage the variability of solar resources, and the Company has not adequately demonstrated that it is appropriate for use in the Company's planning process.

Third, Staff has concerns with the actual implementation of the Integration Cost values into the IRP process.

Q. PLEASE EXPAND ON STAFF'S FIRST CONCERN, THAT THE USE OF THE RIS INAPPROPRIATELY PENALIZES SOLAR RESOURCES FOR OPERATIONAL CHARACTERISTICS.

A. The RIS is designed to attempt to quantify incremental costs to the system resulting from operational characteristics of solar resources related to production variability. By assigning a specific cost to only one category of resources (i.e. solar) based on such characteristics, the Company is unfairly treating certain resources when compared to others. The Company operates its system with a diverse portfolio of resources, each with certain advantages and disadvantages. However, the Company is only attempting to penalize solar resources for some of its characteristics without similarly considering qualities of other generation types. For example, some base load units are not able to operate flexibly, so the Company must have a portfolio that includes sufficient flexible units such as CTs or BESS units. Similarly, units can sometimes have forced outages, which requires the Company to have sufficient contingency reserves on the system. Transmission lines can trip, fuel-based resources can face fuel constraints, and load itself can be highly variable. None of these characteristics are assigned a separate cost in the IRP process.

In planning its system, the Company considers the qualities of its resources and develops an IRP that meets projected load at the lowest cost. Starting with the 2022 IRP, the Company allowed the capacity expansion model to select solar resources as part of an optimized system. However, solar is the only resource for which the Company conducts a subsequent analysis to assign a separate cost of integration into the rest of the grid.

This inconsistent treatment of resources runs counter to the integrated nature of the Company's IRP analysis. The Company's planning studies and capacity expansion models are designed to identify the least-cost portfolio that meets projected load and maintains a reliable system. Solar resources are selected by the model as part of the optimized portfolio, rather than identified as part of a separate process.

The Company has previously acknowledged the significance that solar resources are now identified as part of the optimized capacity expansion analysis. In the 2022 IRP, the Company removed the Generation Remix component from the RCB Framework. The Company noted that:

> *This component was appropriate in the past since incremental renewable resources were not included in previous IRP Resource Mix Studies. The 2022 IRP Resource Mix Study includes incremental renewable resources, which results in the bulk impacts of future renewable resources being fairly represented in the IRP cases. As such, it is appropriate to evaluate renewable resources consistent with other resource types and remove the Generation Remix category.*

(Docket No. 44160, Company Response to STF-DEA-2-37).

A similar argument applies to the Integration Cost component. The system is planned as a whole, identifying a diverse portfolio of resources that contribute to a least-cost, reliable system. Singling out one resource (solar) to assign an arbitrary cost is contradictory to the Company's otherwise integrated planning approach.

Q. PLEASE EXPAND ON STAFF'S SECOND CONCERN, THAT THE RIS IS A THEORETICAL EXERCISE THAT HAS SHORTCOMINGS AND FLAWS.

A. The RIS methodology does not quantify a specific cost that is actually incurred by the Company to manage the variability of solar generation. The Company has acknowledged that the "flexibility violations" as they are identified in the model on a 5-minute basis are not events that specifically lead to violations of North American Electric Reliability Corporation ("NERC") criteria which are assessed on a 30-minute basis (Company Response to STF-PIA-3-39). The Company has also previously testified in the 2022 IRP proceeding that the "flexibility violations" identified in the model only "indicates that there's pressure on the ability of the system to meet those requirements for the BAL standard. Doesn't indicate that there's going to be a violation, but there's pressure on the real time balancing…" (Docket No. 44160, Company Direct Hearing Transcript (Tr.) at 524-525).

Even as a theoretical analysis that is designed to provide an indicative estimate of the effect of solar on the grid, the RIS contains multiple methodological shortcomings and flaws that make the results unreliable for the purposes used by the Company. Specifically, the methodology models a hypothetical system that is significantly less flexible and reliable than the actual Southern Company system. Some of the results of the analysis are not rational, suggesting that the methodology is not suitable for the purpose of the analysis. These flaws result in an overestimate of the costs of integrating additional solar resources.

Q. PLEASE ELABORATE ON STAFF'S CONCERN THAT THE RIS IS NOT MEASURING CONDITIONS THAT IMPOSE ACTUAL COSTS ON THE SYSTEM.

A. The condition that the study is identifying is the "flexibility violation". In the modeling, a flexibility violation is recorded whenever there is a calendar day "in which the system was unable to balance load and resources plus the required level of regulating and spinning reserves… for five minutes or longer" (Technical Appendix Vol. 2, Section 5, p. 17). There are multiple ways in which this modeled condition does not represent a grid condition that actually creates a cost.

First, the model records a flexibility violation whenever the system is unable to balance generation and demand on a five-minute basis, while maintaining 1,250 MW of operating reserves (Company Response to STF-PIA-3-42). The significance of this is that essentially the Company is not allowing the model to use the operating reserves to help balance load, which is precisely what operating reserves are designed to do. There is no restriction in NERC rules that limit the ability of a utility to use operating reserves in order to manage variability (Company Response to STF-PIA-12-12).

Second, and as noted above, the model simulates grid conditions on a five-minute basis. However, the NERC rules that the Company cites as the driver for this analysis require managing Area Control Error ("ACE") on a 30-minute basis (Company Response to STF-PIA-3-39.a). It is highly possible that there could be an imbalance on a 5-minute basis that is resolved within 30 minutes and would thus not result in an ACE violation and may not require any incremental cost for mitigation. Staff requested information from the Company regarding the number of flexibility violations that lasted 30 minutes or more, but the Company stated that the model "does not output standard intra-hour data to allow for this analysis" (Company Response to STF-PIA-3-39.b).

Q. PLEASE ELABORATE ON STAFF'S CONCERN THAT THE METHODOLOGY USED BY THE COMPANY ARTIFICIALLY CREATES A SYSTEM THAT IS LESS FLEXIBLE THAN GEORGIA POWER'S ACTUAL SYSTEM.

A. As discussed above, the methodology used for the RIS creates a reference case system and study cases for each solar tranche in the analysis. However, in developing the reference case, the Company creates a system that is less flexible than its system today, and significantly less flexible than the system expected in the study year of 2028.

When the Company developed the reference case, it manually removed all existing and planned solar and BESS resources. This includes 9,286 MW of solar resources and 509 MW of BESS (Company Response to STF-PIA-3-26 Attachment). The Company stated that the rationale for this change is that, in order to assess the benefit of adding flexible battery storage to the system to address solar variability, the reference case removed all battery storage to create a baseline condition (Tr. at 426). According to the Company, this approach ensures that the RIS "accurately captures the integration costs of solar resources, excluding any impact from embedded flexible BESS resources" and that "BESS resources are receiving the proper credit for helping to mitigate solar intermittence" (Company Response to STF-PIA-12-7). However, by removing the already committed BESS resources, the Company is modeling a system that is less flexible and less reliable than what the actual grid is expected to be in 2028, which is the modeled year, particularly after the Company adds the BESS units approved in the 2022 IRP, 2023 IRP Update, and any additional resources selected as part of Georgia Power's recent and future capacity RFPs. It is conceivable that when Georgia Power adds sufficient flexible BESS resources, there could be little or no issues managing incremental variability due to solar resources, and thus the RIS is overestimating the cost of integrating solar resources.

This finding highlights another methodological shortcoming, that the model uses the most flexible resources as operating reserves but then does not actually use the operating reserves to address the variability.

Q. PLEASE EXPLAIN THE IMPLICATIONS OF THE COMPANY'S MODELING DECISION TO SET ASIDE THE MOST FLEXIBLE RESOURCES AS OPERATING RESERVES THAT ARE NOT THEN ABLE TO ADDRESS SOLAR VARIABILITY.

A. As noted above, the analysis records a "flexibility violation" whenever the model is unable to meet load and maintain at least 1,250 MW of operating reserves. This means that operating reserves are not permitted to be used to manage the variability of load or solar output and prevent a "flexibility violation." As noted by the Company, "Due to the flexibility of BESS resources, the SERVM model prioritizes these resources to meet these operating reserves. If BESS capacity is assigned to provide these capacity reserves, that same capacity is then unavailable to provide intra-hour volatility support" (Company Response to STF-PIA-3-42).

This aspect of the modeling is problematic because, counterintuitively, any incremental variability introduced to the system must be addressed by a set of resources that do not include the most flexible resources on the grid. Combined with the fact that the Company removed existing and planned flexible BESS resources from the reference case, this creates a hypothetical system that is less equipped to manage the system as compared to the actual Southern Company system and overestimates the cost of integrating solar.

Q. HOW DOES THE COMPANY EXPLAIN THIS ELEMENT OF THE METHODOLOGY?

A. The Company stated that because batteries are the best operating reserves, the model selects them first, and sets them aside so they cannot be used to address solar variability:

> *[B]atteries provide reserves at essentially zero operating costs. There's no fuel being burned, like in a [spinning] reserve. So because they provide this reserve at a very, very low cost and a high level of efficiency, like very rapid response, the model likes to use those for that 1,250-megawatts of standard reserves. And so* ***when you start adding batteries to the model -- it likes to set them aside****, it's kind of stingy with them -- it likes to set them aside and say, I'm going to hold these for my reserve requirements.* ***Now, once it gets that 1,250 first megawatt of battery, then that extra megawatt is then available for that rapid response****. And so what we see is we have to force some extra storage into the solutions before you see the full benefit of storage, but -- because you need to meet both types of reserves, and it likes to do it all with batteries.*
>
> Emphasis added. (Tr. at 433-434)

The consequence of this element of the modeling methodology is that the study may be overestimating the amount of BESS capacity needed to mitigate the modeled flexibility violations and thus underestimating the value of adding BESS resources.

The Company also notes that their perspective is that the capabilities of resources to address grid volatility should be used to support load volatility, and not variability of solar output:

> *[T]he flexibility or ramping capability provided by the existing generation in the System is needed to address intra-hour load volatility and other operational uncertainties. This existing System flexibility was not intended to manage solar volatility. Permitting solar volatility to diminish current system flexibility jeopardizes the System's ability to effectively manage load and operational variability.*
>
> (Company Response to STF-PIA-3-24.a)

Q. DOES STAFF AGREE WITH THE COMPANY'S POSITION THAT THE CAPABILITIES OF GRID RESOURCES SHOULD BE ASSIGNED TO ONE SOURCE OF VOLATILITY OVER ANOTHER?

A. No. The system is planned and operated as a whole, and it is unreasonable to "assign" certain grid capabilities to certain loads or resources on the grid. Reserves are used for a range of purposes to respond to volatility, system contingencies, unplanned generator and transmission line outages, and others.

Q. ARE THERE ANY OTHER METHODOLOGICAL FLAWS THAT STAFF WOULD LIKE TO HIGHLIGHT?

A. Yes. As noted above, the Company opted to model an islanded system for the RIS (Technical Appendix Vol. 2, Section 5, p. 12). In reality, the Company does not operate an islanded system, and there are reliability benefits to an integrated system that help the system manage voltage, meet load, and manage variability. As noted in the RIS when defining the flexibility violation, "because of the frequency bias and response of the interconnect, a flexibility violation event does not likely represent an actual loss of load" (Technical Appendix Vol. 2, Section 5, p. 17). This "response of the interconnect" helps the Company maintain reliability and is omitted from the analysis due to modeling as an islanded system.

Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE COMPANY DEVELOPING A REFERENCE CASE THAT IS LESS FLEXIBLE AND RELIABLE THAN THE ACTUAL SYSTEM.

A. Altogether, the factors discussed above create a system that is significantly less flexible than the current system, and certainly less flexible than the system is anticipated to be in the 2028 study year. This creates a modeling condition that is more likely to find flexibility violations in both the reference case and in the study cases and contributes to the conclusion that the results are not a reliable method to evaluate whether the variability of solar resources creates a quantifiable cost to the system.

Q. PLEASE ELABORATE ON STAFF'S CONCERN THAT THE RESULTS ARE NOT REASONABLE.

A. There are multiple ways in which the model produces unreasonable or irrational results, with two specific examples discussed below. First, the results of the RIS find that, counterintuitively, the addition of a solar resource results in a need to carry additional operating reserves in the overnight hours. Second, the RIS analysis produced questionable results regarding the amount of CT resources needed to meet target reliability metrics.

Q. PLEASE DESCRIBE THE ISSUE WITH THE INCREASE IN OVERNIGHT OPERATING RESERVES.

A. The model results show that in order to meet system variability, in some circumstances the model needed to commit resources overnight in order to address variability during solar production hours (Company Response to STF-PIA-3-45). This is due to the specific operational characteristics of some resources on the system such as startup time, minimum up time, and minimum downtime.

The early commitment of these resources results in a production cost which is tracked by the model as part of the impact of mitigating flexibility violations, but the Company is unable to isolate and separately quantify these production costs from early commitment of resources during overnight hours (Company Response to STF-PIA-12-10).

It is unlikely that this system condition would actually occur in reality, and the Company has not provided any testimony or evidence that it ever commits resources during overnight hours to provide operating reserves to address variability of solar during daylight hours

(Tr. at 429-431). This appears to be a circumstance created by the specific modeling approach used by the Company for this analysis, one that is exacerbated by the issue described above, that the model uses the most flexible resources as operating reserves that are not permitted to be utilized to address flexibility violations.

Q. PLEASE DESCRIBE THE ISSUE RELATED TO THE REMOVAL OF CT CAPACITY TO MEET THE TARGET RELIABILITY STANDARD.

A. As described above, when the Company develops the reference case, it removes all solar and BESS and adds 3,800 MW of CT resources to meet a target loss of load expectation ("LOLE") of 0.1 days per year (Company Response to STF-PIA-3-31.b). Then, to create the study cases, the Company adds a tranche of solar resources. This solar addition improves the reliability of the system, so the Company removes some of the CT resources to get the system back to a target LOLE of 0.1 days/year.

The table below summarizes the amount of CT capacity removed from each of the study cases in order to meet the LOLE target and calculates the net addition of solar and CT capacity for each study case.

Table 3. CT Capacity additions for each RIS scenario

Scenario	Solar Capacity Added (MW)	CT Capacity Added to Reference Case (MW)	CT Capacity Removed in Study Case (MW)	Net CT Capacity Addition (MW)
1	7,500	3,800	2,875	925
2	10,000	3,800	2,850	950
3	15,000	3,800	3,050	750
4	20,000	3,800	2,980	820
5	25,000	3,800	2,830	970

(Table derived from data provided in Company Response to STF-PIA-3-31b and STF-PIA-3-34).

This table indicates that the study is producing some irrational results. Starting with Scenario 1, the Company's analysis indicates that adding 7,500 MW of solar capacity and 925 MW of CT capacity meets the same LOLE reliability standard as adding 3,800 MW of CT capacity to the grid. Then, moving to Scenario 2, the Company adds 2,500 MW of incremental solar *and adds* 25 MW of incremental CT capacity to meet the same LOLE level. Lastly, moving to Scenario 3, adding another 5,000 MW of solar enables a *reduction* of 200 MW of CT capacity to meet the same LOLE standard. The directionally inconsistent results continue in Scenarios 4 and 5.

The Company notes that "Each scenario's calibration was conducted independently and should not be directly compared" (Company Response to STF-PIA-3-34). This indicates that the Company acknowledges that the results are inconsistent between study cases. This inconsistency suggests that the study is not producing a reliable quantification of costs to the system.

Q. PLEASE DESCRIBE STAFF'S THIRD CATEGORY OF CONCERN, RELATED TO THE ACTUAL IMPLEMENTATION OF THE INTEGRATION COST VALUES IN THE IRP.

A. The Integration Cost used by the Company in the 2025 IRP capacity expansion modeling was based on the analysis in the 2021 RIS, rather than the updated RIS conducted in 2024, because the 2024 study was not completed in time for use in the Resource Mix Study

(Company Response to STF-PIA-12-3). There were some significant changes in the SERVM cases between 2021 and 2024, and the use of outdated results could potentially have an impact on the final values used in the IRP.

Q. WHAT VALUES WERE USED IN THE RESOURCE MIX STUDY?

A. The Company used an Integration Cost of $1.52/MWh starting in 2025, with values escalating at inflation (Company Response to STF-PIA-5-11). This value is derived from the 2021 study results for a future system that has added some BESS resources to mitigate solar variability.

Q. DOES STAFF HAVE CONCERNS WITH THE INTEGRATION COST VALUES?

A. The values are relatively low, and are thus unlikely to have impacted the selection of solar in the Resource Mix Study. However, for future IRPs, Staff recommends that the Company schedule its analysis such that an updated RIS can be completed prior to commencement of the Resource Mix Study so that the latest results can be incorporated in the Company's planning process.

Q. HOW WILL THE COMPANY USE THE INTEGRATION COST VALUES IN FUTURE RESOURCE RFPS?

A. As a component of the RCB Framework, the Integration Cost values are an element of avoided costs using the "best cost" methodology that is used in evaluating renewable RFPs. The Company has indicated that it intends to use the results of the 2024 RIS in future RFPs if it is approved by the Commission as part of this IRP filing. Staff's understanding is that the Company intends to use the Integration Cost calculation tool that was developed as part of the 2024 RIS, which produces an Integration Cost for incremental solar resources and a Flex Credit for incremental BESS resources. The tool produces these values given a dynamic, user-determined level of existing solar and BESS resources on the system. This will allow the Company to potentially update the values for each future renewable RFP given the results and procurements from prior RFPs.

Q. DOES STAFF HAVE ANY CONCERNS WITH THIS APPROACH TO DETERMINING THE INTEGRATION COST FOR FUTURE RFPS?

A. Not in principle. However, there are several significant uncertainties about how the Company will determine the specific values of existing or committed solar and BESS resources, and what the implications of those values will be on the Integration Cost and Flex Credit values. Staff recommends that the Commission direct the Company to engage with Staff well in advance of the next renewable RFP to establish the assumptions and procedures used in updating the Integration Cost and Flex Credit values before they are used in future renewable RFP evaluations.

Q. WHAT ARE STAFF'S CONCLUSIONS REGARDING THE RIS?

A. The Company has not demonstrated that the RIS provides a reasonable estimation of costs incurred by the system due to the variability of solar. On a fundamental level, it is inappropriate for the Company to assign extra costs to solar resources due to its operating characteristics when the Company does not similarly consider the characteristics of other resources. Furthermore, the Company's RIS methodology is not designed to quantify actual costs incurred by the Company due to the presence of solar resources and artificially models a system that is less flexible than the Company's actual system. The result is that the RIS is likely overestimating the cost of integrating solar resources into the system, and that future improvements to the methodology could produce more reasonable results. Even with that overestimation, the Integration Cost values produced by the RIS are currently relatively low and are unlikely to impact either the results of the Resource Mix Study or the evaluation of bids in future renewable RFPs. Therefore, while Staff has several concerns with the RIS, both in principle and in practice, Staff does not object to the continued use of the study at this time.

Q. WHAT ARE STAFF'S RECOMMENDATIONS REGARDING THE RIS?

A. Staff has three recommendations related to the RIS. First, the Company should consider improvements to the methodology to more accurately reflect the flexibility of the system and its ability to address solar variability. Second, the Company should finalize the next RIS far enough in advance of the 2028 IRP so the results can be used in the Resource Mix Study. Third, the Company should engage with Staff prior to the next renewable RFP to determine how the specific Integration Costs and Flex Credits will be determined using the results of the 2024 RIS.

III. RECOMMENDATIONS ON RCB FRAMEWORK

Q. HAS THE COMPANY PROPOSED ANY UPDATES TO THE RCB FRAMEWORK?

A. Yes. In the 2025 IRP, the Company made two primary changes to the RCB Framework that were approved in the 2022 IRP Order Adopting Stipulation. First, the Company formalized a REC component, which was approved as part of the stipulation between the Company and Staff in the 2022 IRP (Docket No. 44106, Order Approving Stipulation, July 29, 2022, p. 28).

The second change is that the Company has removed the Deferred Transmission Investment component and replaced it with a Locational Transmission Value component (IRP Main Doc., p. 82. See also, Technical Appendix Vol. 2, Section 4, pp. 9-10).

Q. HOW DOES THE COMPANY PROPOSE CALCULATING THE REC COMPONENT?

A. The RCB Framework, as filed with the IRP, does not contain any details regarding the methodology to calculate the REC component. The RCB Framework document simply states: "When it is anticipated that REC value can be realized in a liquid market, the projected value should be based on a reputable market forecast. To calculate REC value in years beyond available forecast data, an appropriate compound annual growth rate may be used" (Technical Appendix Vol. 2, Section 4, p. 11).

In recent RFPs, the Company has been using the methodology proposed in the Joint Recommendation filed after the 2022 IRP, noting that REC values will utilize "REC pricing provided by Evolution Markets, a company that specializes in providing environmental commodity market data and analytics" (Docket No. 44160, Joint Recommendation, July 6, 2023, p. 2). Furthermore, the Joint Recommendation states that:

> *The value of RECs for years in which Evolution Markets has a REC price will determine the REC price to be used in those years of the forecast. To calculate the REC value in subsequent years of the REC forecast, a compound annual growth rate, calculated using Solar Ground-Mounted Tracking technology data from the Company's most recent Avoided Cost filing in Docket No. 4822, will be applied. The starting point used in the compound annual growth rate calculation will coincide with the start of the Company's long-term natural gas price forecast, which supports the Company's annual Avoided Cost filing, while the end point used in the calculation will coincide with the last year of data provided in the Company's annual Avoided Cost Filing.*

(Docket No. 44160, Joint Recommendation, July 6, 2023, p. 2).

Q. DOES STAFF AGREE WITH THE COMPANY'S APPROACH TO CALCULATING THE VALUE OF A REC COMPONENT?

A. Staff recommends the continued use of the methodology filed in the Joint Recommendation, using REC prices from a third-party data provided, and extrapolating that value using a compound annual growth rate calculation. If the Company seeks to change the methodology in the future, it should collaborate with Staff regarding a replacement methodology.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL REGARDING THE DEFERRED TRANSMISSION INVESTMENT.

A. The currently approved RCB Framework contains the Deferred Transmission Investment component. This component applies only to DG resources and represents the potential for these resources to "reduce the demand placed on the transmission system and defer or avoid otherwise needed transmission investments" (Docket No. 44160, Technical Appendix Vol. 2, Sec. 5, 2022 IRP RCB Framework, p. 7). In the 2022 RCB Framework, this component was always reflected as a benefit of DG resources. The Company is proposing to replace the Deferred Transmission Investment component with a "Locational Transmission Value" component (IRP Main Doc., p. 82).

Q. HOW DOES THE PROPOSED LOCATIONAL TRANSMISSION VALUE COMPONENT COMPARE TO THE CURRENT DEFERRED TRANSMISSION INVESTMENT COMPONENT?

A. The components are calculated very similarly, with one key difference. The Deferred Transmission Investment component is calculated using the Company's standard transmission planning analysis methods. The Company models a base case without incremental DG solar and identifies needed transmission upgrades over a 20-year horizon. The Company then models a study case, adding DG solar resources to the grid (spread throughout the system), and identifies the transmission upgrades needed over the same 20-year period (Docket No. 44160, Technical Appendix Vol. 2, Sec. 5, 2022 IRP RCB Framework, pp. 11-12). By comparing the transmission buildout for the two cases, the Company identifies which transmission projects can be delayed or cancelled due to the addition of the DG resources. The economic value of that delay is credited to the incremental DG solar capacity on a pro rata basis as part of the DG RFP evaluation.

For the proposed Locational Transmission Value component, the methodology is fundamentally the same, except that instead of spreading the incremental DG solar resources throughout the grid, the Company tests adding DG solar focused in four zones throughout the state, with each zone analyzed separately (Technical Appendix Vol. 2, Sec. 4, pp. 9-10). By analyzing incremental DG solar in the four zones separately, the Company identifies the effect of location-specific solar development on transmission upgrade need and timing. Using these results, the Company calculates a benefit or cost of DG resources, depending on the zone.

Q. WHAT ARE THE RESULTS OF THE COMPANY'S LOCATIONAL TRANSMISSION VALUE ANALYSIS?

A. The Company analyzed four zones: North GA, Metro GA, Central GA, and South GA. The table below summarizes the results of the analysis.

Table 4. Locational Transmission Value results

Avoided Transmission Cost Due to Solar DG	CentralGA	MetroGA	NorthGA	SouthGA
PV (2025 $000)	(112,041)	(365,754)	(74,862)	127,845
Levelized ($ /KW-Yr)	(19.70)	(21.44)	(13.17)	22.48
Levelized (¢ /kWh)	(0.90)	(0.98)	(0.60)	1.03

(Company Response to STF-PIA-3-22 Attachment A PUBLIC DISCLOSURE, Tab: 'SCS Finance – Summary').

In Table 4, negative numbers represent net benefits, and positive numbers represent net costs. These results show that for three of the four zones (North GA, Metro GA, and Central GA), the addition of DG resources yield a benefit for the Locational Transmission Value component. For the South GA zone, the component would be a cost. This indicates that, according to the Company's modeling, adding incremental DG solar in the South GA zone modified the transmission flows and increased the need for transmission upgrades over the study period.

The Company has proposed that the Locational Transmission Value be used as part of future DG RFP evaluations, which is discussed in Section VI of this testimony.

Q. DOES STAFF HAVE ANY CONCERNS WITH THE COMPANY'S METHODOLOGY OR RESULTS?

A. No. The Company's methodology represents a reasonable approach to quantifying the transmission-related locational value of DG solar resources.

IV. UPDATES TO THE ELCC STUDY

Q. WHAT IS THE PURPOSE OF AN ELCC STUDY?

A. The ELCC study is a method of determining the capacity value of resources. The analysis tests the ability of a specific resource type to reliably serve incremental load under a range of loads and grid conditions. Typically, ELCC studies are targeted at intermittent or energy-limited resources (renewables and storage), but the methodology can be used to evaluate conventional resources as well. The Company uses the results of the ELCC study as an input into their analysis regarding the accredited capacity value of renewable resources and BESS.

Q. HAS THE COMPANY UPDATED ITS ELCC STUDY FOR THE 2025 IRP?

A. Yes. The Company conducted a new analysis in 2024 to determine the ELCC of resources to be evaluated in the 2025 IRP (solar, wind, and BESS).

Q. DID THE COMPANY PROPERLY INCLUDE THE ELCC VALUES FOR WIND, SOLAR, AND STORAGE IN ITS IRP EXPANSION MODELING?

A. No. The Company provided copies of the ELCC studies it relied on for modeling ELCC values for renewable resources in Aurora (STF-JKA-1-10). While the Company included the ELCC values from the provided worksheets for wind and BESS resources in the Aurora modeling, it did not use the worksheet values for tracking solar.

Q. HOW DOES THE COMPANY MODEL SOLAR AS A CANDIDATE RESOURCE IN AURORA?

A. The Company modeled future solar expansion in its Aurora modeling as a single candidate resource option for tracking solar facilities. The Company assumed no capacity value for these resources during the planning horizon.

Q. DOES THE COMPANY'S ELCC WORKSHEETS INDICATE THAT TRACKING SOLAR FACILTIES PROVIDE ZERO CAPACITY VALUE?

A. No. The Company's ELCC calculations show that even in winter, the next 3,000 MW of tracking solar facilities will have a 5% ELCC value. Additional tracking solar does not result in significant winter capacity value according to the Company's results (Company Response to STF-JKA-1-10 Attachment D).

Q. WHAT IS STAFF'S RECOMMENDATION CONCERNING HOW TRACKING SOLAR SHOULD HAVE BEEN MODELED IN AURORA AS A CANDIDATE RESOURCE?

A. Staff recommends using the Company's ELCC values from its worksheets in the Aurora modeling for 2 tranches of tracking solar.

V. DERMS

Q. WHAT IS DERMS?

A. DERMS is a centralized system-of-systems and is comprised of both hardware and software designed to provide visibility, forecasting, control, and optimization of DER devices in coordination with existing grid real-time operations control systems (Company Response to STF-WG-1-16).

Q. PLEASE DESCRIBE THE CURRENT STATUS OF GEORGIA POWER'S DERMS.

A. In the 2022 IRP, the Commission approved an initial plan for Georgia Power to develop DERMS and in the 2022 Rate Case, the Commission approved a limited budget for initial activities for the development of a DERMS. The Company conducted a DERMS request for information in 2023 and an RFP for a DERMS vendor in 2024 (IRP Main Doc., p. 15).

Q. WHAT SPECIFIC REQUEST HAS THE COMPANY MADE IN THE 2025 IRP REGARDING THE IMPLEMENTATION OF THE PROPOSED DERMS?

A. The Company is requesting approval to continue the implementation and integration of its proposed DERMS for the enhanced control of DER devices in addition to visibility and forecasting capabilities as previously approved in the Company's 2022 Rate Case. The Company stated that further work is required to fully implement and integrate DERMS with the Company's real-time operations platforms and to enable enhanced control operational capabilities as defined in the 2025 IRP (Company Response to STF-PIA-3-14). The Company provided Staff an estimate on its projected spending for the remainder of 2025 through 2028 to fully complete the activities requested in the 2025 IRP (Company TS Response to STF-PIA-3-14).

Q. GIVEN THE LOW PENETRATION OF DER CURRENTLY ON THE COMPANY'S SYSTEM, DOES STAFF BELIEVE THAT DERMS CAN PROVIDE BENEFITS?

A. Yes. The Company is continuing to add DER programs to its program offerings for interested customers. In the 2023 IRP Update, the Commission approved the Company's request to expand its DER program offerings to include two new DER programs for both Company and customer-owned assets. Additionally in this IRP, the Company has proposed multiple DER programs which include the Customer-Sited Solar Plus Storage Pilot, LCOR Program, and a modified CCSP. Staff is aware that most of these DER programs have low participation; however, most are relatively new or still waiting Commission approval.

The enhanced control of DERs through DERMS will support grid reliability and expand potential use cases for DERs that can be reflected in customer program incentive valuations

(Tr. at 150). DERMS provides the platform for optimizing utilization of DERs as adoption increases. By investing in the infrastructure now, Georgia Power will be able to better manage and deploy resources to their best use as they come online, rather than waiting to develop programs after a certain threshold is met. By enabling utility programs that compensate DERs for the value provided to the grid, DERMS could encourage faster adoption. DERs in general are likely to grow in importance as a resource that can be scaled up quickly, typically without significant investment in physical infrastructure (transmission, distribution), allowing the Company to more fully utilize existing infrastructure capacity.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S DERMS REQUEST?

A. Staff recommends approval of the Company's request to continue the implementation and integration of DERMS with the Company's real-time operations platforms. Staff's recommended spending level is for the additional spending for the remainder of 2025 through 2028 which was not already approved by the Commission in the 2022 Rate Case as provided in the Company's Response to STF-PIA-3-14. Staff further recommends that the Company be required to make an annual filing which will provide the current status of the DERMS implementation as well as the amount of the budget that has been spent to date.

VI. RENEWABLE ENERGY PROCUREMENTS

Q. PLEASE DESCRIBE THE RENEWABLE PROCUREMENTS THAT WERE APPROVED DURING THE 2022 IRP.

A. In the 2022 IRP Order Adopting Stipulation dated July 29, 2022 ("2022 IRP Order"), the Commission approved Georgia Power to procure up to 2,100 MW of utility scale renewable resources, sized greater than 6 MW, on behalf of all retail customers and for Commercial and Industrial ("C&I") customer subscriptions through the CARES Program, through two separate RFPs. The Commission also approved Georgia Power to procure up to 200 MW of DG solar resources, sized greater than 250 kW but not more than 6 MW, through two 100 MW RFPs.

Q. PLEASE DESCRIBE THE CURRENT STATUS OF THE UTILITY SCALE RENEWABLE PROCUREMENTS APPROVED DURING THE 2022 IRP.

A. The Company's first Utility Scale RFP ("CARES 2023 US RFP") was issued in 2023 and included 1,250 MW roll-over from prior Utility Scale RFPs for a total procurement target of 2,875 MW. This RFP is still ongoing with an anticipated certification by late July or early August. These resources will have required commercial operation dates ("RCOD") between 2026-2029. Based on market feedback, the CARES 2023 US RFP was modified to allow for RCODs as late as 2029 and included a bid refresh process to facilitate this change.

On January 28, 2025, the Commission approved the Company's request to introduce the concept of "Short-Term Network Service" as part of the approved CARES 2023 US RFP pro forma PPAs, in order to bridge the gap between the commercial operation of bids and the completion of long-lead time transmission network upgrades required for firm transmission service (January 28, 2025 Order in Docket No. 45084).

Currently pending before the Commission are additional changes to the CARES 2023 US RFP Pro Forma PPAs based on concerns of short list bidders regarding the impacts of changes in law and tariffs, including the posting of upgrade security, among other items.

The Company's second Utility Scale RFP ("CARES 2025 US RFP") is expected to be issued in the second quarter of 2025. The bid period for CARES 2025 US RFP will open in June and will seek to procure approximately 475 MW, plus roll-over MW from the CARES 2023 US RFP, of utility scale renewable resources, with anticipated RCODs as early as 2029.

Q. PLEASE DESCRIBE THE CURRENT STATUS OF THE DG PROCUREMENTS APPROVED DURING THE 2022 IRP.

A. The first DG RFP ("2023 DG RFP") was issued during 2023. The 2023 DG RFP sought to procure renewable energy of approximately 193 MW, which included 93 MW unfilled from previous DG procurements, with anticipated RCODs in 2025. This RFP concluded on January 6, 2025, and the Commission certified 12 projects totaling approximately 41 MW.

The second DG RFP ("2024 DG RFP") was issued on October 8, 2024. This RFP is still ongoing and seeks to procure approximately 250 MW, which included 150 MW unfilled from the 2023 DG RFP, of DG renewable resources, with anticipated RCODs in 2026.

Q. DID THE COMPANY RECEIVE FEEDBACK ON THE DG RFP DOCUMENTS BEFORE ISSUING THE 2023 DG RFP?

A. Yes. In the 2022 IRP Order, Staff was to convene a DG Working Group ("DGWG") meeting at least 60 days prior to the release of the draft documents for the first DG RFP, to enable collaborative group discussion regarding the proposed RFP and PPA documents. The DGWG was required to consist of 5 Staff members, 5 Solar Association representatives, 5 Georgia Power representatives, and 5 members from the general public who were to be appointed by the Commission Chairman and subject to approval by the full Commission. The DGWG met before both the 2023 and 2024 DG RFPs. Proposed modifications and other feedback by DGWG participants were considered by the Company in the final RFP and PPA documents for each respective DG RFP.

Q. HISTORICALLY HAS THE COMMISSION ALLOWED UNFILLED MW FROM RENEWABLE PROCUREMENTS TO BE ROLLED FORWARD TO SUBSEQUENT RENEWABLE PROCUREMENTS?

A. Yes. In both recent RFPs, DG and utility scale, the Commission approved unfilled MW from prior solicitations to be rolled over to future RFPs.

Q. DOES STAFF SUPPORT ROLLING OVER ANY UNFILLED MW FROM THE 2024 DG AND 2025 CARES UTILITY SCALE RFPS TO FUTURE RENEWABLE PROCUREMENTS?

A. Yes. In order for the total MW of renewable energy that was approved by the Commission to be eventually procured, Staff is supportive of any unfilled MW from the current DG and utility scale RFPs rolling forward to subsequent respective RFPs. Staff also supports that any unfilled MW from future DG and utility scale RFPs continue to roll forward on an ongoing basis to subsequent respective RFPs.

Q. IN THE 2025 IRP, WHAT IS THE TOTAL AMOUNT OF RENEWABLE RESOURCES THAT THE COMPANY IS REQUESTING TO PROCURE?

A. Georgia Power is seeking approval to procure 1,000 MW of utility scale renewable resources through an RFP to be issued in 2026, with the ability to procure up to 4,000 MW. The Company is also requesting approval for an additional 100 MW of DG renewable resources to be procured through two 50 MW DG RFPs to be issued in 2026 and 2027 (IRP Main Doc., pp. 79-81).

1. <u>UTILITY SCALE RENEWABLE PROCUREMENTS</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED UTILITY SCALE RENEWABLE PROCUREMENT STRATEGY.

A. The Company has proposed to procure 1,000 MW of utility scale renewable resources and/or renewable resources paired with renewable or grid-charged storage systems for all customers using the best cost and multi-phase procurement approach. The Company requested the ability to procure up to an additional 3,000 MW if needed to meet customer subscription demand (IRP Main Doc., pp. 79-80).

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE CURRENT UTILITY SCALE PROCUREMENT PROCESS.

A. The Company is proposing several modifications to the current utility scale renewable procurement process. These proposed changes include flexible CODs, a buydown option, and an extended RFP period, which may include multiple phases (IRP Main Doc., pp. 79-80).

Q. PLEASE DESCRIBE HOW THE EXTENDED RFP AND MULTI-PHASE APPROACH WOULD WORK.

A. In order to meet customer subscription demand, if projects are still needed after the short list for the utility scale RFP has been determined, the Company proposes two phases to be implemented. Phase I would include a "buy down" process whereby projects that were not selected as part of the short list but were part of the competitive tier, will be able to buydown their bid price to meet the average total net benefit of the selected short list portfolio.

After completion of Phase I and if customer subscription demand still has not been met, the Company proposes to initiate Phase II. Phase II will allow new projects to be submitted at prices that meet or exceed the average total net benefit of the initial short list. During this phase, customer identified resources would also be allowed to be submitted on behalf of potential CARES subscribers at prices and terms that protect non-participating customers (IRP Main Doc., pp. 79-80).

Q. WHY DID THE COMPANY PROPOSE TO OFFER A CUSTOMER IDENTIFIED RESOURCE OPTION AS PART OF THE UTILITY SCALE RENEWABLE PROCUREMENT PROCESS?

A. The Clean Energy Buyers Association ("CEBA") filed a letter agreement that it had cosigned with Georgia Power. The letter agreement committed CEBA and Georgia Power to meet prior to the 2025 IRP to discuss the development of a carbon free energy customer program for large C&I customers, to be included in the Company's 2025 IRP (April 5, 2024 Letter Agreement in Docket No. 55378). Georgia Power met with CEBA regarding customer-identified carbon-free resources, which led to the proposed modification to the CARES Subscription Program (IRP Main Doc., p. 12).

Q. DOES STAFF HAVE ANY CONCERNS RELATED TO THE COMPANY'S PROPOSED CHANGES TO THE UTILITY SCALE PROCUREMENT PROCESS?

A. Staff is supportive of the requested modifications to the utility scale procurement process since changes are necessary to procure enough renewable energy to meet customers' demands and that these proposed changes protect retail customers. Regarding Flexible CODs, Staff, the Company, and the Independent Evaluator ("IE") will need to determine what changes, if any, will be needed to the Utility Scale RFP evaluation. During the Direct

Hearing, Company Witness Mallard confirmed that this might be an issue that will need to be resolved if flexible CODs are approved by the Commission (Tr. at 878).

Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S PROPOSED UTILITY SCALE PROCUREMENT STRATEGY INCLUDING THE PROPOSED CHANGES TO THE PROCURMENT PROCESS?

A. Yes. Staff recommends approval of the Company's request to procure 1,000 MW of utility scale renewable projects for all customers and up to an additional 3,000 MW to satisfy customer subscriptions. With the understanding that Staff, the IE, and the Company will resolve any concerns related to the evaluation of bids with flexible CODs, Staff also recommends approval of Georgia Power's request to allow bidders to provide flexible CODs and the use of a multi-phase approach which would include customer identified resources. The Company's proposal that bids for Phase I and II meet the average total net benefit of the selected short list portfolio provides protection to retail customers.

2. <u>DG PROCUREMENTS</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED DG PROCUREMENT STRATEGY.

A. The Company has proposed to procure 100 MW of new DG solar resources through two separate RFPs, along with the ability to procure additional resources above the initial MW targets to meet the needs of the proposed DG Subscription Program. Similar to the utility scale procurement process, Georgia Power has proposed to use a multi-phase approach. As proposed, Phase I will allow bidders that were not selected for the target list to buy down their bid price to meet the average of the total net benefit of the selected portfolio. If needed, Phase II would allow new projects, including customer identified resources, to be submitted at the average of the total net benefit of the target portfolio.

The Company also proposes allowing flexible DG resources, resources that are paired with a storage device that are either solar-charged or grid-charged, to participate in future DG RFPs. In order for flexible DG resources to be able to participate, the Company has requested additional visibility and control of such facilities through DERMS. As discussed earlier in the testimony, the Company also proposes to modify how DG resources are evaluated by replacing the Deferred Transmission component of the RCB Framework with a geographic locational value (IRP Main Doc., pp. 81-82).

Q. DOES STAFF HAVE ANY CONCERNS RELATED TO ANY PROPOSED CHANGES TO THE DG PROCUREMENT PROCESS?

A. Yes. For the most part, Staff is supportive of the Company's requested modifications to the DG procurement process. Regarding the request to allow flexible DG resources to participate in future RFPs, Staff is not fully aware of how the requirement that the project be visible and controlled through DERMS could impact future flexible DG bid prices. When this question was posed to the Company, the Company stated that they are still in the process of determining requirements and cost estimates to bidders that would enable DERMS integration with DG RFP solar projects (Company Response to STF-PIA-3-3.i). Staff is generally supportive of allowing bidders the option to bid in flexible CODs. As required, and supported by Staff, for the DG procurement process, the requirement that bids for Phases I and II must meet the average of the total net benefit of the selected portfolio is a protection for retail customers.

Q. DOES STAFF HAVE ANY CONCERNS RELATED TO ANY PROPOSED CHANGES TO THE DG PROCUREMENT EVALUATION METHODOLOGY?

A. Regarding flexible CODs, Staff, the Company, and IE will need to determine what, if any, changes will be needed to the current DG RFP evaluation process.

Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S DG PROCUREMENT STRATEGY INCLUDING THE PROPOSED CHANGES TO THE PROCUREMENT PROCESS?

A. Yes. Staff recommends approval of the Company's request to procure 100 MW of DG resources, including unfilled MW from the 2024 DG RFP, with or without renewable-charged or grid-charged storage facilities, through two RFPs. Staff is supportive of Georgia Power's requests to allow flexible resources to participate in the future DG RFPs but would like to know more regarding how this requirement will impact bid prices. Staff also recommends approval of the multi-phase approach, including customer identified resources, to assist in procuring resources needed to meet customer subscription demand. The requirement for projects to meet the average of the total net benefit of the selected portfolio will protect retail customers. Staff further recommends approval of the Company's request to use a locational transmission value in future DG RFP evaluations.

Regarding flexible CODs, Staff, the Company, and the IE will need to determine what, if any, changes will be needed to the current DG RFP evaluation process.

Q. PLEASE DESCRIBE THE COMPANY'S CCSP.

A. The existing CCSP was approved by the Commission on May 26, 2020 in Docket No. 43107. The CCSP allows participating customers to sell 100% of the output from their solar facility at an escalating rate over an agreed upon term. Eligible solar facilities are required to be sized between 1 kW - 3 MW and located on or adjacent to their property. Program guidelines require participants to have at least one Georgia Power meter on its premises at least six months prior to applying for the program. The Commission extended the CCSP application period until the allocated 25 MW capacity is fulfilled (December 8, 2021 Order in Docket No. 43107). Currently, there is only one project sized at 1.5 MW participating in the CCSP.

Q. IN THE 2025 IRP, DID THE COMPANY PROPOSE TO MODIFY THE CCSP?

A. Yes. The Company proposed to modify the current CCSP in order to encourage additional projects to participate. The Company proposed to modify the eligible minimum and maximum project sizes to 250 kW and 6 MW, respectively. In addition, the Company has proposed that new customers be allowed to participate, in addition to existing customers, and that storage can be paired with the solar facility. Participant compensation will be based on the energy and capacity values the facilities are projected to deliver to the grid (IRP Main Doc., pp. 103-105).

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S PROPOSED MODIFICATION TO THE CCSP?

A. Since there is only one CCSP project currently participating in the program, Staff agrees that changes are necessary in order to fully subscribe the MW allotment for this program. Staff recommends approval of the Company's proposed modifications to the CCSP.

VII. CUSTOMER-SITED SOLAR PLUS STORAGE PILOT PROGRAM

Q. DID THE COMPANY PROPOSE A NEW RESIDENTIAL AND SMALL COMMERCIAL SOLAR PLUS STORAGE PILOT?

A. Yes. The Company has proposed the Customer-Sited Solar Plus Storage Pilot Program. The Commission's 2023 IRP Update Order Adopting Stipulation directed Georgia Power to evaluate and develop a residential and small commercial solar and battery pilot program that will provide grid reliability and capacity benefits. This Order also required the Company to have at least two collaborative meetings with Staff and interested parties prior to finalizing its proposal (April 26, 2024 Order in Docket No. 55378).

Q. DID THE COMPANY MEET WITH INTERESTED PARTIES PRIOR TO FINALIZING THE CUSTOMER-SITED SOLAR PLUS STORAGE PILOT PROGRAM?

A. Yes. Staff facilitated two meetings which were held at the Commission on July 10, 2024 and September 5, 2024. At these meetings, the Company discussed pilot program planning principles, design objectives, and potential learnings. Interested parties were also given an opportunity to present on potential pilot program design options, best practices from other jurisdictions, and pilot size considerations.

Q. PLEASE DESCRIBE THE PROPOSED CUSTOMER-SITED SOLAR PLUS STORAGE PILOT PROGRAM.

A. Georgia Power is seeking approval to add up to 50 MW of residential and small commercial solar and battery facilities through two participation options, Company-Directed and Customer-Directed. The target participation amount for each option is 25 MW. The Company has proposed that system sizes be capped at 20 kW for residential customers and 250 kW, or no more than 125% of metered load, for commercial customers. As proposed, participants must take service on a Company-approved rate other than the residential tariff ("R") for residential customers or the general service tariff ("GS") for commercial customers. The solar plus storage systems may be owned by the customer or another party (IRP Main Doc., pp. 103-104). The Company has committed to making the Customer-Directed option available only through this IRP Cycle (Tr. at 1190).

Q. PLEASE DESCRIBE HOW THE PROPOSED 50 MW TARGET WAS DETERMINED.

A. The Company stated that the 50 MW target was established in consideration of the expected volume of customer applications and prior experience implementing customer-sited renewable programs (Company Response to STF-PIA-3-8.a). During the Direct Hearing, the Company's witnesses were asked whether the Company would request a program expansion if the target MW for either pilot program option was reached. Company witnesses confirmed that the 50 MW target was intentionally not labeled as a cap and that program expansion could be considered to accommodate new subscribers prior to the next IRP (Tr. at 884-886).

Q. PLEASE DESCRIBE THE PROPOSED CUSTOMER-DIRECTED OPTION.

A. The Customer-Directed option will be available for both new and existing solar plus storage and standalone BESS resources. This program option will use discrete events with performance-based payments whereby participating customers will receive a small annual enrollment incentive of $15/kW and an ongoing incentive payment of $1.50/kWh. The Company has proposed a larger upfront enrollment incentive of $45/kW for low-to-moderate income residential and municipalities, universities, schools, and hospitals ("MUSH") commercial customers. The minimum number of hours that can be called in each annual period is 50 with a maximum event duration of four hours (IRP Main Doc., p. 104). If a participating customer does not meet the minimum number of hours called in each annual period, the customer would not be eligible for the annual incentive (Tr. at 1203).

Q. PLEASE DESCRIBE THE PROPOSED COMPANY-DIRECTED OPTION.

A. The Company-Directed option is available for customers with new BESS assets paired with new or existing behind the meter solar that meet technical and performance requirements. This program option would allow the Company to maintain continuous operation of the BESS by paying an upfront enrollment incentive of $750/kW with no ongoing performance incentive to participating customers. The Company has proposed that low to moderate income residential and MUSH commercial customers be eligible for a larger upfront enrollment incentive of $1,000/kW (IRP Main Doc., pp. 104-105).

Customers must enter a 10-year contract tied to the premises that allows the BESS to be fully controlled by the Company which will not be charged below a 20% state of charge ("SOC") and operated in accordance with the manufacturers' requirements (IRP Main Doc., pp. 104-105).

Q. DID THE COMPANY DESIGN THE PROPOSED CUSTOMER-SITED SOLAR PLUS STORAGE PILOT PROGRAM AFTER OTHER UTLIITY PROGRAMS?

A. Yes. The Company reviewed and considered similar programs from the following utilities: Duke Energy, Rocky Mountain Power, Green Mountain Power, Arizona Public Service, National Grid, and Xcel Energy (Company Response to STF-PIA-3-8.i). The Company considered and included design elements proposed by interested parties. Specifically, the Company stated that the 50 MW threshold, 20% SOC minimum for the Company-Directed option, and residential system sizes greater than 10 kW were suggested by interested parties (Tr. at 936, 1152, and 1185).

Q. HOW WERE THE PILOT PROGRAM CUSTOMER INCENTIVES DETERMINED?

A. Incentive payments for both options are based on the current system value of capacity and calculated using the 75% shared savings model. This methodology is consistent with how incentive payments for the DER Colocation ("DCL") Program, DCO, and the proposed LCOR are also calculated. The kW basis of the incentive values uses the lower of the maximum continuous discharge of the BESS or the energy storage capacity divided by four for the Customer-Directed option or 80% divided by two for the Company-Directed option (IRP Main Doc., pp.104-105). The current system value of capacity is based on the net present value of the retail capacity price forecast. For the Company-Directed option, the incentive was calculated by taking 75% of the capacity price over a 10-year period. For the Customer-Directed option, the capacity price for one annual period was spread over 50 hours to come up with the ongoing performance incentive (Tr. at 1188-1189).

Q. PLEASE DESCRIBE HOW THE TARGET FOR THE CUSTOMER SITED SOLAR PLUS STORAGE PILOT PROGRAM WILL BE INCREASED.

A. The Company has stated that if the 50 MW target is reached, the Company will assess the impacts and propose options for the Commission to move forward with the pilot (Company Response to STF-PIA-3-8). During the Direct Hearing, Company Witness Beppler further clarified that the intent of not labeling the 50 MW target as a cap was to go beyond that amount with some potential modifications (Tr. at 1221).

Q. HOW WILL THIS PILOT PROGRAM BE ADMINISTERED?

A. The Company intends to use a third-party aggregator to administer both pilot program options and facilitate participation from multiple brands and configurations of BESS assets (IRP Main Doc., p. 104). The resources will be controlled via an aggregator through a grid-edge DERMS, instead of a centralized DERMS (Tr. at 1146). Another program that will use a grid-edge DERMS to interface with the Company's centralized DERMS will be the TempCheck Program (Tr. at 421-422).

Q. DID THE COMPANY PROVIDE PROGRAM DOCUMENTATION OR CUSTOMER AGREEMENTS FOR THE PROPOSED CUSTOMER-SITED SOLAR PLUS STORAGE PILOT PROGRAM?

A. No. The Company has not yet developed a proposed customer agreement or other applicable program documentation (Company Response to STF-PIA-3-8.h). Once the Commission approves the pilot program, the Company will seek an implementation partner and make a compliance filing which will allow stakeholder feedback (Tr. at 887).

Q. WHAT CONCERNS DOES STAFF HAVE REGARDING THE PROPOSED CUSTOMER-SITED SOLAR PLUS STORAGE PILOT PROGRAM?

A. Staff has several concerns regarding the proposed Customer-Sited Solar Plus Storage Pilot Program. The first concern is regarding how potential participants in the pilot program will be made aware of the remaining capacity for each pilot program option. During the Direct Hearing, Georgia Power Witnesses were asked this question, and the Company responded that notification of remaining capacity for the pilot program would be something that would have to be worked out with Staff (Tr. at 1182-1183). Staff and the Company addressed a similar concern during the RNR Monthly Netting Pilot. Ultimately, it was decided that the best approach was to post information for future participants on the Company's website instead of a monthly or quarterly filing requirement.

Staff's second concern is that a better process needs to be formalized regarding how the Company will request to increase the targets before the pilot program becomes fully subscribed. The Company stated during the Direct Hearing that they would not wait until the next IRP to request to increase the pilot program cap; however, a specific process to increase the pilot program targets has not been proposed. Additionally, Staff is concerned regarding the proposed rate limitations for participating customers as it can limit pilot participation. Any potential impacts from participating customers on the "R" or "GS" rates should be tracked and included as part of the pilot lessons learned. Approximately 80% of residential customers that currently have solar and/or BESS at their premises are on the R rate (Company Response to STF-PIA-15-1 Attachment).

Lastly, Staff is concerned that the Company has only committed to making the pilot available through this IRP cycle. For the Customer-Directed option, the short commitment will make it more difficult for potential participants to make investment decisions given that they can only count on a maximum of three years of incentive payments. This will not impact customers on the Company-Directed option as the full incentive is paid upfront.

Q. DOES STAFF RECOMMEND THE APPROVAL OF THE PROPOSED CUSTOMER-SITED SOLAR PLUS STORAGE PILOT PROGRAM?

A. Yes. Staff recommends approval of the Proposed Customer-Sited Solar Plus Storage Pilot Program conceptually. There are still items that need further discussion and finalization prior to implementation of the pilot program.

VIII. CUSTOMER PROGRAMS

1. <u>CARES PROGRAM</u>

Q. PLEASE DESCRIBE THE EXISTING CARES SUBSCRIPTION PROGRAM.

A. The current CARES Program provides renewable subscription options for Georgia Power's C&I customers and was modeled after the REDI C&I and Customer Renewable Supply Procurement Programs. As approved, the CARES Program offers carve-outs for MUSH, an option for around-the-clock carbon-free energy from carbon-free resources, Economic Development, Existing Load and New Load options. The CARES Program was designed to support participating customers in meeting their sustainability goals and to deliver projected long-term energy savings to all Georgia Power customers.

Q. DID THE COMPANY PROPOSE CHANGES TO THE CURRENT CARES SUBSCRIPTION PROGRAM?

A. Yes. Using lessons learned from the current CARES Subscription Program, the Company has proposed an enhanced CARES Utility Scale Program and a new CARES DG Subscription Program / Community Solar Program. As proposed, these programs will allow customers to subscribe to a portion of the energy output and/or RECs from a portfolio of renewable resources approved in this IRP (IRP Main Doc., pp. 96-99).

2. CARES UTILITY SCALE SUBSCRIPTION PROGRAM ENHANCEMENTS

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ENHANCEMENTS TO THE CARES UTILITY SCALE SUBSCRIPTION PROGRAM.

A. The Company has proposed enhancing the current CARES Utility Scale Subscription Program through a few modifications. The first phase will mimic existing processes and subscriptions will be offered through an enhanced notice of intent process and allocated to interested customers through a Commission-approved methodology. Customers will be offered subscriptions to the output of the resulting resource portfolio for terms of 10-30 years, in five-year increments. Customer subscriptions will be priced using either of the two CARES pricing mechanisms, the CARES REC-based fixed program portfolio charge with no hourly energy credit, or the CARES fixed program charge based on the PPA price, with a corresponding hourly energy credit. Georgia Power also proposed a new concept to modify the price calculation methodology for the hourly energy credit to reduce the risk to non-participating customers by establishing reimbursement thresholds as part of the subscription. Specific modifications to the hourly energy credit modifications were not provided in the Company's IRP filing.

As proposed, Phase II of CARES would be conducted if customer demand for subscriptions exceeds the amount of MW procured through Phase I or if customers choose to participate through a customer identified resource procurement. Projects participating in Phase II must result in a total net benefit at or above the total net benefit of the selected short list portfolio.

Customers who submit a customer identified resource will negotiate directly with a project developer and all hourly energy credits and RECs associated with this resource will be assigned to the corresponding customer subscriber (IRP Main Doc., p. 97).

Q. WHY HAS THE COMPANY PROPOSED MODIFICATIONS TO THE CARES UTILITY SCALE SUBSCRIPTION PROGRAM?

A. The demand for RECs through subscription mechanisms such as CARES has outpaced the available supply due to the growth of new and existing customers with sustainability goals. At the same time, the Company's recent Utility Scale RFPs have not been successful at meeting the procurement targets. Georgia Power has proposed changes due to feedback from customers and developers in order to provide flexibility and optionality for customers to increase the chances of procuring additional renewable resources (IRP Main Doc., pp. 96-97).

Q. HAS THE COMPANY FULLY DEVELOPED THE PROPOSED CARES SUSBSCRIPTION HOURLY ENERGY CREDIT PRICING METHODOLOGY TO ENSURE THAT BENEFITS ARE ACCURATELY ALLOCATED BETWEEN PARTICIPATING AND NON-PARTICIPATING CUSTOMERS?

A. No. According to Company Witness Mallard, the Company's subscription pricing methodology is still conceptual at this point. Details of the methodology will be presented to the Commission for approval and feedback from interested stakeholders through the program approval process (Tr. at 966).

Q. DOES STAFF RECOMMEND APPROVAL OF GEORGIA POWER'S PROPOSED ENHANCEMENTS TO THE CARES UTILITY SCALE SUBSCRIPTION PROGRAM?

A. Yes. Staff recommends approval of the proposed enhancements to the CARES Utility Scale Subscription Program. Staff will review the proposed subscription pricing methodology once filed for Commission approval.

3. CARES DG SUBSCRIPTION PROGRAM

Q. PLEASE DESCRIBE THE PROPOSED CARES DG SUBSCRIPTION PROGRAM.

A. The Company has requested approval of the CARES DG Subscription Program which will be available to C&I customers with an aggregate demand between 1 MW and 3 MW and residential customers. These customers will be able to subscribe to output from DG resources that are procured in future RFPs. The proposed term for residential customers will be at least ten years. Customers will be able to choose between REC pricing options of either a fixed price charge with no hourly energy credit or a fixed program charge based on the PPA price, with a corresponding hourly energy credit. The Company also has proposed to modify the price calculation methodology in order to reduce the risk to non-participating customers. An additional phase of the DG RFP will be conducted if subscription needs are not fully met or a customer identified resource is submitted. RECs associated with a customer identified resource will be retired on behalf of the subscriber (IRP Main Doc., p. 98).

Q. WHY DID THE COMPANY PROPOSE THE CARES DG SUBSCRIPTION PROGRAM?

A. Georgia Power proposed the CARES DG Subscription Program as an additional option to help customers meet their renewable and sustainability goals. Both residential customers and eligible C&I customers, who otherwise would not be able to participate in the CARES Utility Scale Subscription Program, will be able to participate in the CARES DG Subscription Program. This new program option will provide customers with more options to subscribe to carbon-free resources, while adding flexibility and optionality to the RFP process for both bidders and subscribers (IRP Main Doc., pp. 98-99).

Q. PLEASE DESCRIBE THE PROPOSED RESIDENTIAL DISTRIBUTED GENERATION COMMUNITY SOLAR PROGRAM.

A. The proposed Distributed Generation Community Solar Program will allow residential customers the opportunity to subscribe to the output of DG RFP resources. As proposed, the first 10 MW of the initial 50 MW target of each DG RFP would be available for subscription by residential customers. Similar to the CARES Utility Scale Subscription Program, but simplified, pricing would be based on the PPA price, with an energy credit calculated from the annual average value of the DG facility's production based on the Company's hourly operating costs of incremental generation per kWh. Georgia Power is also exploring opportunities to partner with third parties to reduce subscription prices for lower income customers (IRP Main Doc., pp. 98-99).

Q. WILL PARTICIPATING CUSTOMERS HAVE THE OPPORTUNITY TO SAVE MONEY BY PARTICPATING IN THE PROPOSED RESIDENTIAL DG COMMUNITY SOLAR PROGRAM?

A. Yes. As Company Witness Mallard testified during the Direct Hearing, depending on the length of term, if avoided costs are higher than the DG Community Solar Program subscription price, there's a potential that the customer can benefit (Tr. at 954-955).

Q. PLEASE DESCRIBE THE COMPANY'S EXISTING COMMUNITY SOLAR PROGRAM.

A. Georgia Power's existing Community Solar Program provides customers the opportunity to support the development of solar power in Georgia by subscribing to a portion of the output of a portfolio of solar resources. The program was designed to collect program costs from participating customers, whereby blocks of community solar offset a customer's purchase of delivered energy by the amount of energy produced at the community solar facilities equivalent to the customer's subscription level. In the 2022 IRP Order, the Commission approved the Company's amended Community Solar Program, which included an Income-Qualified Community Solar Pilot, but denied the Company's request to increase the residential and commercial block charges, which were to be considered in the 2022 Rate Case.

In the 2022 Rate Case Order Adopting Settlement Agreement as Modified, the Commission set the pricing for the Community Solar Program at $24 per block for residential customers and $25 per block for commercial customers (December 30, 2022 Order in Docket No. 44280). As of January 1, 2025, 1,163 residential customers have subscribed to 2,036 blocks and 1 commercial customer has subscribed to 1 block out of 8,000 available blocks (Company Response to STF-PIA-8-1 Attachment in Docket No. 44160). There have not been any corporate sponsors to fund the Income-Qualified Community Solar Pilot (Company Response to STF-PIA-8-4 in Docket No. 44160).

Q. WHY DID THE COMPANY PROPOSE A DG SUBSCRIPTION COMMUNITY SOLAR PROGRAM INSTEAD OF MODIFYING THE EXISTING COMMUNITY SOLAR PROGRAM?

A. Georgia Power proposed the DG Community Solar Program as an option for customers to subscribe to lower-priced resources in which the customers receive RECs along with energy credits. By leaving the existing Community Solar Program in place while the new program is approved and rolled out, the Company will gauge which option(s) to continue in the 2028 IRP or beyond (Tr. at 951-952).

Q. DOES STAFF RECOMMEND APPROVAL OF GEORGIA POWER'S PROPOSED DG SUBSCRIPTION COMMUNITY SOLAR PROGRAM?

A. Yes. Conceptually Staff is supportive of another program option for customers. Staff will review the Company's proposed modifications to the contract energy price when the program documents are submitted for Commission approval. Staff further recommends that the Company be required to make quarterly filings which will provide the current level of DG Community Solar Program subscriptions, by month.

IX. DER PROGRAMS

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT DER PROGRAM OFFERINGS.

A. The Company currently offers DER programs such as the DER Customer Pilot Program, implemented through the Resiliency Asset Service Tariff ("RAS") and Demand Response

Credit Tariff ("DRC"), which was approved as part of the 2022 IRP Order on a pilot basis with an overall cap of 250 MW. RAS provides resiliency service to participating customers through the installation and operation of a Company-owned DER behind the customer's meter. DRC allows for a participating customer in RAS to receive credits on their bill in exchange for a reduction of the customer's electric demand through the Company's control of the DER during periods of extreme supply and demand conditions.

In the 2023 IRP Update Order, the Commission approved two additional DER programs, DCL and DCO. Both programs are supply-side programs where participating customers will have dispatchable DERs with firm fuel supply that can provide energy to the system. Customers who sign up for DCO can currently only participate through 2031. There are no participants for the currently approved DER Programs (Tr. at 859).

Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED LCOR PROGRAM.

A. Georgia Power is seeking approval of an additional DER Program offering, the LCOR. LCOR is designed for transmission connected customers who own their DER with a firm fuel supply (Company Response to STF-PIA-3-12). There is no proposed maximum size for customers load reduction under this program. This program requires the installation and performance of non-emergency generators with a firm fuel supply.

To allow for operational certainty of the demand response when called upon, customers will be isolated from the grid if no response is received from assets during events called under Energy Emergency Alert conditions (Company Response to STF-WG-1-11). Unlike

DCO and DCL, Commission approval would not be required for customers to sign up under the proposed LCOR Program as this program will operate more like a demand side option.

Q. HOW IS THE LCOR PROGRAM DIFFERENT FROM THE COMPANY'S CURRENT DER PROGRAMS?

A. The LCOR Program creates a new large C&I customer-owned option that is not available in the current DER programs. The new resiliency option will restrict the customer's DER from pushing back to the grid which changes the way such DER is interconnected. Rather than being a supply-side option, the program will operate as a demand-side program, such that the customer's DER is behind the meter and reduces the customer's load (Tr. at 856-857).

Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED MODIFICATIONS TO THE DER CUSTOMER-OWNED PROGRAM.

A. Under the current DCO, customers can only sign up for the program through 2031. The Company has proposed to modify the DCO program to allow for contract terms up to 15 years (IRP Main Doc., p. 107).

Q. DID THE COMPANY PROVIDE PROPOSED TARIFFS OR CUSTOMER AGREEMENTS FOR THE PROPOSED RESILIENCY PROGRAM OR THE AMENDED CUSTOMER-OWNED PROGRAM?

A. No. The Company has not yet drafted the proposed tariffs or customer agreements but plans to file these with the Commission for approval following the conclusion of the 2025 IRP (Company Response to STF-PIA-3-12).

Q. WHAT CAPACITY VALUE HAS BEEN INCLUDED IN THE RESOURCE LEDGER FOR THE COMPANY DER PROGRAMS?

A. The Company has not reflected any capacity value on the resource ledger for the existing DER Programs or the proposed LCOR Program. Company Witness Beppler testified that this was a change from what was filed in the 2023 IRP Update. Since there are not any customers participating in the DER programs, the Company has removed the capacity value from the resource ledger. When a customer does sign up, the Company will add their resource's capacity contribution to the resource ledger (Tr. at 861-862).

Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S DER REQUESTS?

A. Yes. Staff recommends approval of the LCOR Program and the proposed term modification for the DCO Program.

X. ADDITIONAL SUM

Q. DID THE COMPANY REQUEST AN ADDITIONAL SUM FOR THE RENEWABLE RESOURCES REQUESTED IN THIS IRP?

A. Yes. The Company has requested a levelized additional sum of $4.00/kW-yr for the total capacity amount from which renewable energy is procured from the utility scale and DG RFPs proposed in this IRP, annually for the term of each PPA (IRP Main Doc., p. 5).

Q. HAS THE COMPANY REQUESTED AN ADDITIONAL SUM FOR ANY OTHER RENEWABLE PROGRAM?

A. Yes. The Company has requested a levelized additional sum of $4/kW-yr for the total capacity amount from the proposed LCOR Program, Customer-Sited Solar Plus Storage Pilot Program, and the modified CCSP (IRP Main Doc., p. 4).

Q. WHAT IS THE MOST RECENT COMMISSION APPROVED ADDITIONAL SUM METHODOLOGY FOR RENEWABLE RESOURCES?

A. In the 2022 IRP Order, the Commission approved an additional sum for both utility scale and DG resources at a levelized $4.00/kW-yr.

Q. DOES THE GEORGIA CODE PROVIDE FOR AN ADDITIONAL SUM?

A. Yes. O.C.G.A. §46-3A-8, states that the Company is entitled to an additional sum, as determined by the Commission, for purchased power resources. This Code section also describes certain factors that shall be considered by the Commission, such as lost revenues, changed risks and equitable sharing of benefits between the Company and ratepayers in determining the appropriate additional sum required to encourage long-term power purchases. However, while the Georgia Code sets forth certain factors that the Commission must consider in setting the additional sum, neither the Act nor Commission Order set forth any specific methodology or formula to calculate that additional sum.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S REQUEST FOR AN ADDITIONAL SUM FOR ITS PROPOSED RENEWABLE PROCUREMENTS AND PROGRAMS IN THIS IRP?

A. Staff recognizes that an additional sum based on total net benefits which has been approved for renewable resources procured during RFPs prior to the 2022 IRP, will likely result in a low additional sum. Staff recommends that Georgia Power receive an additional sum of $3.00/kW-year as it appropriately balances the interests of the Company and customers.

XI. V2X PILOT

Q. DID THE COMPANY PROPOSE ANY OTHER PILOT PROJECTS AS PART OF ITS 2025 IRP?

A. Yes. Georgia Power has proposed a V2X pilot to transfer energy stored in underutilized batteries to buildings, houses, and the grid. The Company has proposed to evaluate V2X technology starting with a pilot with public school systems, to install up to 10 chargers (IRP Main Doc., pp. 108-109).

Q. WHAT WERE SOME OF THE REASONS THE COMPANY PROPOSED THE V2X PILOT PROJECT?

A. Georgia Power noted that as the energy landscape continues to evolve, new and emerging technologies have the potential to fundamentally alter the way energy is created, transported, and ultimately consumed, to benefit customers and the grid. The Company has proposed to enhance system flexibility, resiliency, and economics by leveraging underutilized batteries in the EV market (IRP Main Doc., p. 108).

Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S PROPOSED V2X PILOT PROJECT?

A. Yes. Staff recommends Commission approval of the Company's V2X Pilot Project. Staff further recommends an annual filing that provides the status of the pilot and the amount of the budget that has been spent to date.

Q. DOES THIS CONCLUDE STAFF'S TESTIMONY?

A. Yes.