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February 28, 2025

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

RE: **Georgia Power Company's 2025 Integrated Resource Plan; Docket No. 56002 and Georgia Power Company's 2025 Application for the Certification, Decertification, and Amended Demand-Side Management Plan; Docket No. 56003**

Dear Ms. Tanner:

Enclosed for filing on behalf of Georgia Power Company is (1) the Direct Testimony of the Panel of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, (2) the Direct Testimony of the Panel of Dr. Ross Beppler, Carley Goff, A. Wilson Mallard, and Andy Phillips, and (3) the Direct Testimony of the Panel of Jennifer S. McNelly and Robert W. Mitchell, III.

Please call me at (404) 885-3779 if you have any questions regarding this filing.

Sincerely,

Allison W. Pryor

Allison W. Pryor

Enclosure

**STATE OF GEORGIA**

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

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

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| **Georgia Power Company's** | **)** | **Docket No. 56003** |
| **2025 Application for the Certification,** | **)** | |
| **Decertification, and Amended** | **)** | |
| **Demand-Side Management Plan** | **)** | |

**DIRECT TESTIMONY OF**

**JEFFREY R. GRUBB, J. RANDY HUBBERT, M. BRANDON LOONEY,**

**MICHAEL B. ROBINSON, AND FRANCISCO VALLE**

**FEBRUARY 28, 2025**

# DIRECT TESTIMONY OF
# JEFFREY R. GRUBB, J. RANDY HUBBERT, M. BRANDON LOONEY, MICHAEL B. ROBINSON, AND FRANCISCO VALLE

## IN SUPPORT OF GEORGIA POWER COMPANY'S 2025 INTEGRATED RESOURCE PLAN DOCKET NO. 56002

## AND

## APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND SIDE MANAGEMENT PLAN DOCKET NO. 56003

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.**

A. My name is Jeffrey R. Grubb. I am the Director of Resource Planning for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is James "Randy" Hubbert. I am the Southern Company Services ("SCS") Resource Planning Director. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

A. My name is Michael "Brandon" Looney. I am the Reliability Planning Manager for SCS. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

A. My name is Michael B. Robinson. I am the Vice President for Grid Transformation for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is Francisco Valle. I am the Director of Forecasting and Analytics for SCS. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

**Q. MR. GRUBB, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I began my career with Georgia Power in 1992 as a cooperative education student in Commercial and Industrial Marketing. I graduated from the Georgia Institute of Technology in 1996 with a Bachelor of Science degree in Mechanical Engineering. After joining the Company as a full-time employee in 1997, I worked in various roles within Marketing until 2001 at which time I participated in a Company developmental program where I gained experience in a wide range of functional areas. During this period, I earned a Master of Business Administration degree from Auburn University in 2000.

In 2003, I joined the Resource Policy and Planning organization at Georgia Power where I served as a Project Manager through 2006. From 2007 through 2016, I worked for SCS in various planning roles including SCS Forecasting Team Leader (2007), SCS Fuels Planning Manager (2007–2011), and SCS Resource Planning Project Manager (2011–2016) where I managed the team that supports the development of the Southern Company System ("System") Integrated Resource Plan ("IRP"). In this role, I supported Georgia Power's 2013 IRP and 2016 IRP. In 2016, I returned to Georgia Power as Project Manager in Resource Policy and Planning. Beginning in March 2018, I assumed my current position of Director of Resource Planning for Georgia Power where I led the development of the 2019 IRP, the 2022 IRP, and the 2023 IRP Update.

**Q. MR. GRUBB, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?**

A. Yes. I have testified in several proceedings before the Georgia Public Service Commission ("Commission"), including: Georgia Power's Application for Certification of the 2023 Biomass Request for Proposals ("RFP") Power Purchase Agreements, Docket No. 44880; Georgia Power's 2023 IRP Update, including the Company's Application for the Certification of Plant Yates Units 8-10 and Application for Certification of Robins, Moody, Hammond, and McGrau Ford Phase II Battery Energy Storage Systems ("BESS"), Docket No. 55378; Georgia Power's 2022 IRP, Docket No. 44160; the Review of Georgia Power's

Public Utility Regulatory Policies Act (PURPA) Avoided Cost Methodology, Docket Nos. 4822, 16573, and 19279; Georgia Power's 2019 IRP, Docket No. 42310; Georgia Power's Application for the Certification of the 2020/2021 Renewable Energy Development Initiative ("REDI") Utility Scale ("US") Power Purchase Agreements ("PPAs"), Docket No. 42625; Georgia Power's Application for the Certification of the 2018/2019 REDI US PPAs, Docket No. 41596; and Georgia Power's Application for the Certification of the 2018/2019 REDI US PPAs for the Commercial and Industrial ("C&I") Program, Docket No. 41734.

**Q. MR. HUBBERT, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated from Mississippi State University in 2001 with a Bachelor of Science degree in Electrical Engineering. I began my career at SCS in the Transmission Planning organization. I moved to Resource Planning in 2005, where I was responsible for administration of RFPs, PPA development and negotiation, and reliability and reserve margin analysis. In 2007, I transitioned back to Transmission Planning and served in various roles responsible for conducting system impact studies for Open Access Transmission Tariff (OATT) customers, RFPs, and Company-owned resources. In 2011, I moved to the Bulk Power Operations organization within SCS as the Transmission Compliance Manager, where I was responsible for ensuring compliance with all applicable NERC reliability standards. In 2014, I transitioned to the System Operations Manager role where I was responsible for managing the real-time Interchange reliability function, Open Access Same-Time Information System ("OASIS") administration, transmission tagging and scheduling, and data integrity functions.

In March of 2016, I moved into the Integrated Resource Planning Manager role at SCS, where I was initially responsible for supporting the development of the System IRP. I subsequently assumed increasing responsibilities, including integrated resource planning, energy budgeting, scenario planning and forecasting, and production cost modeling and analysis for the System. As the Integrated Resource Planning Manager, I supported Georgia Power's 2016, 2019, and 2022 IRPs, as well as the 2023 IRP Update. In 2025, I became the SCS Resource Planning Director, where I am responsible for modeling and analysis for the retail operating companies' capacity and energy requirements. This includes developing annual integrated resource plans and planning scenarios, production cost modeling and energy budgeting, reliability and resiliency planning, and generation asset evaluations.

**Q. MR. HUBBERT, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. No.

**Q. MR. LOONEY, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated from the University of Alabama in 2003 with a Bachelor of Science degree in Mechanical Engineering. I began my career at SCS in the Engineering and Construction Services organization. During this time, I completed my Master of Business Administration from the University of Alabama at Birmingham and received my Professional Engineering License from the State of Alabama. I moved to Research and Environmental Affairs in 2007 as a Research Engineer responsible for environmental control technology with a focus on compliance with the Mercury and Air Toxics Standards ("MATS"). In 2012, I became the Environmental Controls Research Manager responsible for Southern Company's technology research portfolio for air, land, and water pollutants.

In 2013, I transitioned to Southern Company's System Planning organization, where I have held various leadership positions including Asset Management, Renewable Generation Development, and Asset and Environmental Planning. I moved into my current position in 2019, where I have primary responsibility for Reliability Planning including the Reserve Margin Study as well as the evaluation for the Company's numerous RFPs. In these roles, I have supported each Georgia Power IRP dating back to 2016 as well as a number of certification filings.

**Q. MR. LOONEY, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. No.

**Q. MR. ROBINSON, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated from Auburn University in 1993 with a Bachelor of Electrical Engineering. I began my career as a cooperative education student with Georgia Power working in distribution and marketing. After leaving the Company to serve in the United States Navy, I worked for an electric municipality in Texas, the Kerrville Public Utility Board, for five years where I was responsible for all distribution and substation facilities. In 1999, I returned to Southern Company as an engineer on the Enhanced Power Quality team with Alabama Power Company. Throughout my career at Southern Company, I have served in a variety of positions throughout the System, including Principal Engineer in Transmission Planning; Supervisor of the Transmission Maintenance Center in Albany, Georgia; Supervisor of the Transmission Control Center in Valdosta, Georgia; Transmission Planning Manager; South Georgia Area Transmission Manager; Metro South Distribution Manager; and General Manager of Transmission Planning and Operations.

From 2017 through 2020, I served as the Power Delivery Operations General Manager for Georgia Power. I then served as Planning, Operations, and Policy Vice President until January 2024, when I transitioned into my current role as Vice President of Grid Transformation. In my current role, I lead an organization responsible for distribution and transmission planning, administration of the Georgia Integrated Transmission System ("ITS"), data analytics and fiber strategy, grid transformation and federal funding strategy, and compliance. I work with multiple organizations to identify the Company's long-term transmission and distribution strategies to address our future needs. I also actively engage with System and industry partners to appropriately identify industry-wide solutions, alternatives, and emerging technologies.

**Q. MR. ROBINSON, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. Yes, I testified before the Commission in Georgia Power's 2023 IRP Update, Docket No. 55378; Georgia Power's 2022 Rate Case, Docket No. 44280; Georgia Power's 2022 IRP, Docket No. 44160; and Georgia Power's 2019 Rate Case, Docket No. 42516.

**Q. MR. VALLE, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated from the Universidad Técnica Federico Santa María in Valparaíso, Chile in 1997 with a degree in Electrical Civil Engineering. I also hold a Master of Business Administration from Emory University's Goizueta Business School.

I joined Southern Company in 1997 as a Planning Analyst at Edelnor S.A., a subsidiary of Southern Energy Inc., in Santiago, Chile. In 2001, I moved to Atlanta to join Mirant Corporation, where I held multiple roles of increasing responsibility in system planning and market development and gained extensive experience modeling power pools in the United States and valuing generation technologies and demand response ("DR"). Since then, I have worked at SouthStar Energy Services, a subsidiary of Southern Company Gas, and served as the Manager of Risk Analysis Services, a group within the SCS Finance organization. In this role, I was responsible for supporting the selection of optimal financing strategies for Southern Company's debt and equity portfolios and for providing business units with quantitative analysis and risk mitigation strategies. I also supported Georgia Power Market Planning by providing revenue, load forecasting, and risk analysis; performing weather revenue variance analysis; reviewing features of load forecasting models; and more.

In September of 2021, I joined Georgia Power as Director of Market Planning. In this role, I led Georgia Power's Forecast and Profitability & Economic Analysis teams, which produced, among other things, the annual peak demand, energy, and revenue forecasts, as well as profitability evaluations of Demand Side Management ("DSM") programs. In March of 2023, I assumed my current position as Director of Forecasting and Analytics for

SCS. I lead the forecasting team that provides load forecasting services to SCS, Georgia Power, and Mississippi Power Company as well as the quantitative team that supports capital market operations and provides operational analytics.

**Q. MR. VALLE, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. Yes. I testified in Docket No. 55378, Georgia Power's 2023 IRP Update, Docket No. 44160, Georgia Power's 2022 IRP, and Docket No. 44161, Georgia Power's 2022 Application for the Certification, Decertification, and Amended Demand Side Management Plan.

**Q. WHAT IS THE IRP?**

A. The IRP is Georgia Power's comprehensive plan for economically and reliably meeting the electric energy needs of current and future customers over a 20-year planning horizon. Georgia Power develops the triennial IRP as part of a continuous planning process governed by the Commission. The IRP contains the analysis and supporting data that inform the Company's resource planning decisions, including the Company's assumptions and conclusions regarding the impacts of resource options on the future cost and reliability of electric service.

The IRP process provides a structured, robust, and well-reasoned framework through which both demand-side and supply-side resources are equitably evaluated to develop a plan that provides reliable and economical electric energy for customers.

**Q. HOW DOES THE 2025 IRP RELATE TO THE 2023 IRP UPDATE?**

A. The 2023 IRP Update was an interim filing that specifically addressed short-term generation capacity needs associated with rapid, extraordinary load growth. As such, it addressed only those items that needed to be updated - most notably the load forecast, projected capacity needs, and the procurement of resources required to meet those needs. In contrast, the 2025 IRP is a return to Georgia Power's triennial, long-term planning process, as required by statute.[1] The 2025 IRP includes the Company's load and energy forecast, evaluates the existing resources and transmission available to serve that load, identifies capacity needs, and identifies what actions are required, including the procurement of additional resources, to continue providing customers with clean, safe, reliable, and affordable electric service.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. Our testimony supports and requests approval of Georgia Power's 2025 IRP, including the Company's (i) Application for Certification of Wholesale Capacity from Plant Scherer Unit 3; and (ii) Application for Certification of Capacity from Plant McIntosh Units 10-11 and 1A-8A. We incorporate the 2025 IRP as part of our testimony.

**Q. PLEASE SUMMARIZE THE TESTIMONY OF THE PANEL.**

A. The 2025 IRP establishes a comprehensive strategy to meet the forecasted energy needs of customers and our state as it continues to experience extraordinary growth. The Company proposes a reliable, economical, and diverse resource mix to meet Georgia's growing energy needs and provide clean, safe, reliable, and affordable electric service for its customers. The 2025 IRP leverages innovative customer programs and technologies, enhanced generation procurement processes, a combination of previously approved RFPs and incremental resource requests, strategic transmission planning, opportunities offered by existing generation resources, and new demand-side and distributed energy resource options for the benefit of Georgia Power customers.

The 2025 IRP contains an updated load and energy forecast, which addresses the continued strong economic development trends since the Company's 2023 IRP Update with updates to the Company's growing pipeline of potential and committed large load customers.

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[1] *See* O.C.G.A. § 46-3A-2(a) ("On or before January 31, 1992, *and at least every three years thereafter* as may be determined by the commission, each utility shall file with the commission an [IRP] as described in this chapter." (Emphasis supplied)).

Georgia Power's risk-adjusted load forecast for winter peak demand from the winter of 2024/2025 through the winter of 2030/2031 reflects 8,205 megawatts ("MW") of load growth. The Company projects nearly 6,000 MW of load growth as early as the winter of 2028/2029. Over the next ten years—through the winter of 2034/2035—Georgia Power expects up to 9,400 MW of load growth.

Through 2031, Georgia Power projects a capacity need of 9,000 MW, which it plans to address through the actions approved in the 2022 IRP and 2023 IRP Update, as well as the incremental requests proposed in this 2025 IRP. Georgia Power's supply-side strategy enhances the reliability, flexibility, and value of generation resources to serve customer needs. Key elements of this strategy include extensions for existing resources, upgrades of existing resources, hydroelectric ("hydro") modernization, and flexible renewable resource procurement, including seeking to add up to 4,000 MW of incremental renewable resources to the electric system by 2035.

The Company conducted a Reserve Margin Study to determine the necessary target reserve margins ("TRM") to support System reliability. As approved in prior IRPs, the Reserve Margin Study supports the continued use of seasonal planning. The Company recommends maintaining the current 26% long-term Winter TRM for the System and proposes to increase the Summer TRM to 20%.

The Company intends to continue using the Renewable Cost Benefit ("RCB") Framework, consistent with prior Commission approvals, with only minor proposed revisions. In this proceeding, the Company proposes to replace the deferred transmission investment component of the RCB Framework with a locational transmission value component for Distributed Generation ("DG") resources. As revised, the RCB Framework will continue to ensure that Georgia Power's renewable procurement decisions maximize economic and reliability benefits for all customers.

The Company updated the Renewable Integration Study pursuant to commitments made in the 2022 IRP. Updating the Renewable Integration Study supports cost-effective and reliable planning and integration. The Renewable Integration Study indicates that significant increases in solar penetration can be achieved while maintaining appropriate levels of reliability for the System and finds that the cost of integrating renewable resources can be significantly reduced by adding flexible resources, such as BESS. These flexible resources can provide essential grid services more efficiently by providing operating reserves at a lower production cost.

The Company updated its scenario planning design for the 2025 IRP, particularly in response to revised environmental regulations that require retirement, installation of CCS controls, or restricted operation for natural gas combined cycle units. The 111 GHG Rules, among others, are subject to ongoing legal challenges. Accordingly, the Company's scenario planning assumes compliance with these rules as currently on the books while accounting for uncertainty and incorporating appropriate flexibility. This IRP uses nine planning scenarios, three of which use views where 111 GHG Rules are in effect and six of which use views where 111 GHG Rules are not in effect. These provide a flexible framework for the Company to evaluate its options and make resource planning decisions.

Georgia Power's supply side strategy leverages expansion, extension, and investment in existing units while seeking to issue RFPs for additional resources to meet customer needs. The Company's supply-side strategy proposes to continue the operation of Plant Bowen Units 1-4, as well as the extension of six existing units previously granted decertification, to preserve operating capacity. Further, the Company is seeking approval for upgrade projects at 14 existing gas and nuclear units, as well as continued investment in 43 hydro units at nine plants as part of the Company's hydro modernization plan. Georgia Power seeks to issue an All-Source RFP in 2025 for resources to come online in 2032 and 2033. The Company also proposes enhancements to its renewable procurement processes to include a more flexible RFP process that supports additional renewable resources to meet customer subscription demand.

Strategic transmission planning and the measured and disciplined expansion of the electric grid is critical to providing clean, safe, reliable, and affordable energy to customers, especially in times of growth, and is a necessary complement to the required expansion of the Company's generating fleet. As such, the 2025 IRP includes (i) the 2024 Georgia ITS

Ten-Year Plan, including changes since the 2022 IRP and 2023 IRP Update, (ii) updates on strategic transmission projects since the 2022 IRP to address South to North transmission constraints, and (iii) additional considerations for evolving System needs beyond the traditional ten-year transmission planning window.

Serving customers' evolving energy needs requires an integrated, flexible, all-of-the-above, and diversified approach. With the Commission's constructive oversight, Georgia Power's long-term integrated resource planning process – and specifically, the requests set forth in this 2025 IRP – will help ensure the Company can continue to reliably and economically meet the electric energy needs of its customers and Georgia, today and for decades to come.

**Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

A. The remainder of our testimony is organized as follows:

- Section II discusses the Company's load and energy forecast.
- Section III covers reliability, the reserve margin, seasonal planning, the RCB Framework, and the Renewable Integration Study.
- Section IV details the Company's scenario design and expansion planning processes.
- Section V addresses the Company's supply-side strategy, including resource extensions, unit upgrades, and hydro modernization investments.
- Section VI provides the Company's transmission plan and addresses other strategic transmission planning-related issues.
- Section VII outlines the Company's wholesale to retail capacity offer.

**Q. WHAT AREAS OF THE 2025 IRP ARE ADDRESSED BY OTHER WITNESSES?**

A. The Panel of Jennifer McNelly and Brett Mitchell provide testimony on the Company's Environmental Compliance Strategy ("ECS") and the carbon pressures facing the Company's generation fleet. The Panel of Ross Beppler, Carley Goff, Wilson Mallard, and Andy Phillips ("Customer Programs Panel") addresses the Company's DSM Plan and

Application, proposed Distributed Energy Resource ("DER") Customer Programs, and enhancements to the Company's renewable procurement processes and customer renewable programs.

## II. LOAD & ENERGY FORECAST

**Q. PLEASE PROVIDE AN OVERVIEW OF THE LOAD AND ENERGY FORECAST FILED IN THE 2025 IRP.**

A. The Company continues to forecast load and energy for the residential, commercial, industrial, governmental, and MARTA customer groups using its Commission-approved long- and short-term methodologies for the organic forecast, as adjusted for large loads, electric vehicles, behind-the-meter generation, and DSM. The Company's Budget 2025 ("B2025") Load and Energy Forecast projects continued extraordinary customer load growth stemming from substantial economic development in Georgia. The projected demand now far exceeds the demand projected in the 2022 IRP and 2023 IRP Update. As outlined in the Load and Energy Forecast contained in Technical Appendix Volume 1, current projections reflect winter peak demand load growth of 8,205 MW through the winter of 2030/2031, which reflects a compound annual growth rate of 7%. Further, the forecast projects average annual growth in territorial energy sales of 7,900 gigawatt-hours ("GWh") from 2024 to 2034, a substantial increase compared to the past forecasts of 500 GWh in Budget 2022 and 6,200 GWh in the 2023 IRP Update.

**Q. PLEASE DISCUSS THE SCALE AND PACE OF GROWTH AND DEMAND THAT HAS OCCURRED SINCE THE 2023 IRP UPDATE.**

A. The demand projected in the 2025 IRP load forecast exceeds the demand projected in both the 2023 IRP Update and the 2022 IRP. At the time of the 2022 IRP, the Company anticipated just over 300 MW of growth between the winter of 2024/2025[2] and the winter of 2030/2031. For this same period, the Company projected approximately 5,900 MW of growth in its 2023 IRP Update.

By comparison, Georgia Power's risk-adjusted load forecast from the winter of 2024/2025 through the winter of 2030/2031 now reflects 8,205 MW of load growth, representing an increase of more than 2,200 MW compared to the load growth projections in the 2023 IRP Update for the same period. In the near term, the Company projects nearly 6,000 MW of load growth as early as the winter of 2028/2029. Over the next ten years—through the winter of 2034/2035—Georgia Power expects up to 9,400 MW of load growth.

Following the 2023 IRP Update, Georgia Power began filing quarterly large load economic development reports, which update the Commission on the large load economic development pipeline identified by the Company. These quarterly reports track the total number of both committed large load customers[3] and potential large load customers seeking to locate in Georgia. The reports reflect robust growth in the Company's large load economic development pipeline since the 2023 IRP Update. Growth is up by approximately 6.8 GW, from 16 GW at the 2023 IRP Update filing in October 2023 to 22.8 GW by June 2024. Over the same eight-month period, the number of committed large load customers grew by 10 projects to 7.3 GW, representing an increase of approximately 3.7 GW. Committed customers' projects are continuing to materialize and now represent 8.1 GW.

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[2] For purposes of this filing, the winter of two years that are listed together refers to the period from December of the first year through February of the following year. For example, the winter of 2030/2031 refers to the period from December 2030 through February 2031.

[3] Committed customers are those who have executed a Request for Electric Service from Georgia Power. For purposes of forecasting and planning for large load customers, the Company defines "large load" to be industrial load greater than or equal to 45 MW and commercial load greater than or equal to 115 MW.

**Q. PLEASE DISCUSS THE PRIMARY FACTORS DRIVING THE B2025 LOAD FORECAST.**

A. Several factors are contributing to the B2025 Load and Energy Forecast projections. Georgia's economy is continuing to grow, which increases the need for electricity in businesses and factories. The state's population is also growing, leading to more electricity use in homes. The rise in large commercial and industrial customers, such as data centers and manufacturing plants, is contributing to the new demand. Also, the adoption of electric vehicles, both for personal and business use, is steadily driving up electricity consumption. Technological advancements in solar panels, DERs, and smart appliances are changing how people use electricity. Although improvements in energy efficiency help offset some of the demand, they alone are not enough to keep up with Georgia's growing energy needs.

**Q. PLEASE DESCRIBE THE METHODOLOGY USED TO DEVELOP THE COMPANY'S ORGANIC FORECAST.**

A. The methodology used to develop the Company's organic forecast involves the use of Commission-approved econometric techniques that have been utilized in previous proceedings. This methodology includes a careful examination of key demographic and economic variables that are significant drivers of energy consumption. In addition, the Company uses external adjustments to account for new industries and trends not reflected in historical data.

**Q. HOW DOES THE COMPANY ACCOUNT FOR LARGE LOADS IN ITS FORECAST?**

A. Consistent with the approach used in the 2023 IRP Update, the Company continues to adjust its organic forecast using the Load Realization Model ("LRM"). The Company does not assume that all projects within the large load economic development pipeline or even that the full load of committed projects will materialize. The B2025 Load and Energy Forecast accounts for uncertainties related to new large load projects, including factors such as state selection, electric provider selection, project delays, and the degree to which load materializes. In addition, the Company continues to work directly with customers to understand their electric service needs and the timing in which large load projects will come online. The LRM evaluates thousands of potential combinations of existing and potential economic development loads, which can then be sorted and ranked to create a probability distribution. A probability distribution helps the Company assess the likelihood of the loads it will need to serve. The output of the LRM is the basis for the large load external adjustment applied to the Company's organic load forecast. The results from the LRM support the external adjustment applied to the baseline C&I load and energy forecasts.

**Q. HAVE THERE BEEN ANY CHANGES TO THE LOAD REALIZATION MODEL SINCE THE 2023 IRP UPDATE?**

A. The Company continues to use the same probabilistic model developed in support of the 2023 IRP Update. The 2023 IRP Update focused specifically on identifying proposed solutions for near-term challenges associated with rapid, extraordinary load growth. During that proceeding, the Company utilized the 95th percentile (P95) of the large load distribution forecast to ensure the Company would have the resources necessary to reliably serve customers in the near-term considering the accelerated pace of the extraordinary economic growth taking place in Georgia.

The 2025 IRP marks a return to Georgia Power's triennial, long-term integrated planning process. This process involves developing the full load and energy forecast, evaluating the existing resources available on the System to serve that load, identifying any resulting capacity needs, and planning the necessary actions for the coming years. For this reason, in the 2025 IRP, the Company is planning a load consistent with the 50th percentile (P50) of the large load distribution.

**Q. DOES THE COMPANY MAKE ANY OTHER ADJUSTMENTS TO BASELINE LOAD AND ENERGY PROJECTIONS?**

A. Yes. In addition to the large load adjustment discussed above, the B2025 Load and Energy Forecast incorporates adjustments for DSM programs and actions, electric vehicles, and behind-the-meter solar.

**Q. PLEASE ADDRESS THE CHANGES IN SUMMER AND WINTER PEAK DEMANDS SINCE THE 2023 IRP UPDATE.**

A. Since the 2023 IRP Update, Georgia Power's projected summer and winter peak demands have significantly increased. While Georgia Power continues to be a summer-peaking utility, winter peaks are also increasing at a faster rate than previously forecasted. From 2025 to 2031, winter peaks are projected to grow by approximately 8,200 MW, whereas summer peaks are expected to grow by approximately 8,700 MW during the same period. This accelerated growth in winter peaks is attributed to large commercial and industrial customers operating year-round.

## III. RELIABILITY

**Q. WHAT IS "RESOURCE ADEQUACY"?**

A. "Resource Adequacy" refers to the level of resources required to maintain an appropriate level of reliability on the electric system. Accepted utility practice requires that an electric utility maintain sufficient supply- and demand-side resources to adequately serve the electricity needs of its customers, including an appropriate reserve margin. Georgia Power ensures Resource Adequacy through the IRP process, which includes a detailed assessment of demand forecasts and available resources and an updated Reserve Margin Study.

### *A. <u>Reserve Margin Study</u>*

**Q. WHAT IS THE RESERVE MARGIN AND WHAT IS ITS PURPOSE?**

A. The reserve margin represents the difference between the total existing and committed capacity, including the impact of DR programs, and the Company's projected peak demand. The reserve margin is generally expressed as the percentage of existing and committed capacity above the projected weather-normal peak demand (*e.g.*, a reserve margin of 26% means that existing and committed capacity is 26% above the projected winter weather-normal peak demand). In accordance with accepted utility practice, Georgia Power maintains capacity reserves greater than the Company's projected peak demand to achieve the appropriate level of reliability considering various risk factors (*e.g.*, weather, economic growth uncertainty, generator unit performance, and market availability risk) that could cause the actual peak demand, or generation available to meet the peak demand, to differ from projections.

**Q. WHAT IS THE TARGET RESERVE MARGIN?**

A. The target reserve margin ("TRM") is the reserve margin the Company uses for reliability planning purposes. The actual reserve margin will vary over time due to variations in the actual peak demand and resource availability, among other things. In contrast, the TRM remains fixed (until updated through a Reserve Margin Study) and guides the Company's resource planning decisions. The Company evaluates three components in determining the TRM: economic value; risk tolerance; and reliability. The TRM is set at a level that will minimize the combined expected costs of maintaining reserve capacity, production costs, and customer costs associated with service interruptions, while adjusting for risk and maintaining a minimum level of reliability.

**Q. HOW DOES THE COMPANY ESTABLISH ITS TARGET RESERVE MARGIN?**

A. A Reserve Margin Study is conducted by SCS at least every three years. This study allows the Company to establish a TRM for the System considering the costs and risks to customers and the reliability of the System. The target reserve margin for each of the retail operating companies is then determined, taking into consideration the benefits of System reserve sharing and load diversity.

**Q. WHY IS THE RESERVE MARGIN STUDY CONDUCTED AT A SYSTEM LEVEL?**

A. A well-designed Reserve Margin Study should represent how an electric system commits and dispatches resources to meet energy demand. Georgia Power participates in a System pooling arrangement and coordinated planning, and it is appropriate that the Reserve Margin Study be consistent with that arrangement.

**Q. HOW DO POOL DISPATCH AND COORDINATED PLANNING BENEFIT GEORGIA POWER CUSTOMERS IN THE CONTEXT OF THE TRM?**

A. Pool dispatch and coordinated planning provide several benefits for Georgia Power customers as they relate to the TRM. The pooling arrangement optimizes System dispatch and provides for a lower overall System production cost, which puts downward pressure on the reserve margin. The pooling arrangement also allows the System to capture the benefits of load diversity, which leads to a lower target reserve margin for each individual pool participant. Coordinated planning allows for temporary reserve sharing, which may be available to resolve short-term deficits to an individual operating company's target reserve margin.

**Q. IS THE COMPANY REQUESTING TO CONTINUE SEASONAL PLANNING AS APPROVED IN THE 2019 AND 2022 IRPS?**

A. Yes. The Company's 2024 Reserve Margin Study supports Georgia Power's plans to continue to use seasonal planning to address weather-related reliability risks during the summer and winter. Given that customer load response and resource performance vary across the summer and winter peak periods, it is necessary to evaluate Resource Adequacy in both the summer and winter peak periods to ensure that System reliability has been appropriately evaluated. Moreover, since seasonal planning was approved in the 2019 IRP, major reliability events encountered across the country have reinforced the importance of seasonal planning.

**Q. WHICH SEASON PRESENTS THE GREATEST RELIABILITY RISK?**

A. The Reserve Margin Study continues to support that the greatest reliability risk exists in the winter season due to the following drivers: (1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) the distribution and duration of peak loads relative to the norm; (3) cold weather-related unit outages; (4) the penetration of solar resources which correlate more directly to summer peak periods; (5) increased reliance on natural gas which can be constrained in winter peak periods; and (6) market purchase availability.

**Q. WHAT ARE THE WINTER AND SUMMER TARGET RESERVE MARGINS THE COMPANY IS SEEKING APPROVAL FOR IN THIS CASE?**

A. The Company is seeking approval of the current 26% long-term Winter TRM for the System and approval of a 20% Summer TRM, an increase from the currently approved 16.25% Summer TRM. For the short term (2024-2026), the Company plans to adopt System targets of 19.5% for summer and 25.5% for winter. These values were used to prepare the 2025 IRP filing.

**Q. HOW DID THE COMPANY DETERMINE A 20% SUMMER TRM WAS NEEDED?**

A. Compared to the results of prior reserve margin studies, the 2024 Reserve Margin Study indicates that the reliability risk for the System is higher than in past years due primarily to sustained high loads across overnight hours observed in recent winter weather events. Thus, with a higher System reliability risk, the seasonal TRM necessary to maintain the Company's minimum loss of load expectation ("LOLE") threshold is also higher.

If the current 26% Winter TRM and 16.25% Summer TRM are retained, the LOLE for the System results in an annual LOLE of one event every eight years, which is well below the

Company's minimum reliability threshold of one event in 10 years ("1:10 LOLE"). Because the 1:10 LOLE threshold is an annual metric, a reliability change in one season can impact the TRM in the other season required to maintain the 1:10 LOLE. As a result, one of the TRMs, Summer or Winter, must increase to ensure an adequate level of annual System reliability for customers.

The current Summer equivalent of a 26% Winter TRM is 24.76%. Since reliability in the winter season is still driving the Company's capacity needs, and winter capacity resources are typically available in the summer, an increase of the Summer TRM to 20% is not expected to increase the need for capacity resources on the System. Thus, to meet its reliability needs without driving the need for additional capacity resources, the Company elected to increase the Summer TRM rather than the Winter TRM.

### ***B. <u>Renewable Cost Benefit Framework</u>***

**Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE RCB FRAMEWORK.**

A. The RCB Framework is the Company's established methodology for determining the costs and benefits of renewable resources on the System. The RCB Framework guides resource planning, procurement, and payment activities related to renewable resources and ensures economic and reliable renewable resource integration into the System.

**Q. WILL GEORGIA POWER CONTINUE USING THE RCB FRAMEWORK IN THE 2025 IRP?**

A. Yes. The Company intends to continue using the RCB Framework consistent with prior approvals by the Commission. The Company continues to consider ways to improve RCB effectiveness and requests to replace the deferred transmission investment component with a locational transmission value component, as specified in Technical Appendix Volume 2.

**Q. PLEASE EXPLAIN HOW THE RCB FRAMEWORK INCORPORATES AND CONSIDERS LOCATIONAL VALUE.**

A. The Company proposes to reflect local transmission value as a benefit or cost in the RCB Framework for applicable resources submitted into the DG RFPs based on resource location. Technical Appendix Volume 2 provides further information regarding this proposed change. The deferred transmission investment component of the RCB Framework—which is applied to all resources in the DG RFP evaluation process, regardless of location—will be replaced with a geographically differentiated transmission system value in the evaluation process. This change will ensure the portfolio of resources selected provides the maximum benefits to Georgia Power customers. Under the proposed framework, the Company determines the value by evaluating two alternative future system scenarios, one with and one without additional DG resources for each identified geographic region. The transmission investments and in-service timing of projects are also determined for each scenario's study horizon. The DG analysis is performed based on traditional transmission expansion planning, focusing on how DG resources impact the required in-service date of any identified projects.

**Q. WHAT IS THE BENEFIT OF THE COMPANY'S PROPOSAL TO INCLUDE LOCATIONAL VALUE IN THE RCB FRAMEWORK?**

A. Renewable DG resource portfolios will be selected with consideration of the locational transmission value of the individual resources, resulting in resource portfolios that deliver higher value to customers due to better alignment with long term transmission expansion needs.

**Q. HOW WILL THE COMPANY APPLY THE UPDATED RCB FRAMEWORK AND LOCATION-BASED EVALUATION METRICS TO RENEWABLE RFP BIDS?**

A. The updated RCB Framework introduces a new locational value consideration into the Company's evaluation of DG renewable resources. Instead of assuming that all DG resources, regardless of location, affect the bulk transmission system the same, resources will be evaluated with a location-specific cost or benefit. This will impact the relative ranking and selection of resources in addition to the consideration of other RCB components such as avoided energy costs. By applying these enhanced metrics, the Company can ensure that renewable procurement decisions maximize economic and reliability benefits for all customers. The Direct Testimony of Witnesses Beppler, Goff, Mallard, and Phillips further describes the impact of locational value considerations on the Company's proposed DG RFP evaluation processes.

### *C.* ***Renewable Integration Study***

**Q. IN PREPARING FOR THE 2025 IRP, DID THE COMPANY UPDATE THE RENEWABLE INTEGRATION STUDY IT FILED IN THE 2022 IRP?**

A. Yes. In the 2022 IRP, Georgia Power explained that it would update the Renewable Integration Study, similar to the Reserve Margin Study and the RCB Framework, with each IRP. Accordingly, the Company met with the Commission Staff ("Staff") to resolve previously outstanding concerns regarding the Renewable Integration Study and updated the Renewable Integration Study for the 2025 IRP.

**Q. WHY IS IT IMPORTANT TO UPDATE THE RENEWABLE INTEGRATION STUDY?**

A. The Renewable Integration Study evaluates the operational impacts of increased penetration levels of renewable resources on the System. This assessment provides unique insights into certain challenges, opportunities, and most importantly, solutions that enable significant renewable penetration while maintaining a reliable System. The Renewable Integration Study demonstrates that, while renewable integration costs generally increase as more solar is added to the System, the cost is impacted by other resources on the System as well as System cost drivers such as fuel costs. Therefore, updating the analysis supports cost-effective and reliable planning and integration.

**Q. PLEASE DISCUSS THE UPDATED RENEWABLE INTEGRATION STUDY PROCESS AND RESULTS.**

A. The updated Renewable Integration Study indicates that significant increases in solar penetration can be achieved while maintaining appropriate levels of reliability for the System. The Renewable Integration Study also found that the cost of integrating renewable resources can be significantly reduced by adding flexible resources, such as BESS. Maintaining sufficient BESS capacity improves the cost-effectiveness of solar integration, reduces the curtailment of renewable resources, and improves System reliability. In addition, the Renewable Integration Study determined that flexible resources, such as BESS, can provide these essential grid services more efficiently by providing operating reserves at a lower production cost.

## IV. SCENARIO DESIGN & EXPANSION PLANNING

### *A. Scenario Design*

**Q. PLEASE PROVIDE AN OVERVIEW OF GEORGIA POWER'S SCENARIO DESIGN PROCESS.**

A. Many factors affecting resource planning involve future uncertainties. Thus, the Company creates scenarios to understand these future uncertainties and make appropriate planning decisions. Key uncertainties affecting planning include (1) future pressure on carbon dioxide ("$CO_2$") and other greenhouse gas ("GHG") emissions, (2) cost and performance of future generating technologies, (3) future load growth, and (4) future fuel prices. The Company identifies plausible views of the future that are meaningfully different from one another in each of these four areas, which are then combined to create several scenarios. The Company then uses its modeling system, Aurora, to identify a least-cost expansion plan that reliably meets load and satisfies many other conditions.

**Q. HOW DO THE SCENARIOS USED IN THE 2025 IRP COMPARE TO THE SCENARIOS USED IN THE 2022 IRP AND THE 2023 IRP UPDATE?**

A. The design of the 2025 IRP scenarios has changed from the 2022 IRP. As part of its annual refresh of the planning scenarios used to conduct resource analyses, the Company considers updates based on multiple factors, including changes in environmental regulation and legislation, technological developments, revised economic projections, communication with current and potential customers, and revised fuel market conditions. As a result, the Company updated its views of future GHG pressure, future technology cost and performance, future load growth, and future fuel prices. The Company created nine scenarios in support of its expansion planning, each of which employ different combinations of the views in these four key areas.

The 2023 IRP Update scenarios were very similar to the 2025 IRP scenarios apart from the three 111 GHG Rule scenarios that are included in the 2025 IRP scenarios.

**Q. WHAT REGULATORY CHANGES HAVE IMPACTED THE COMPANY'S SCENARIO PLANNING?**

A. As it relates to pressure on $CO_2$ emissions (the first uncertainty listed above), in the spring of 2024, the Environmental Protection Agency ("EPA") finalized its Rules revising Section 111 of the Clean Air Act ("111 GHG Rules"). The 111 GHG Rules require new natural gas combined cycle units to either install and operate carbon capture and sequestration ("CCS") technology by January 1, 2032, or operate to less than 40% annual capacity factor. In addition, existing coal units have three compliance options: (i) retire by January 1, 2032; (ii) capture and sequester 90% of GHG emissions beginning January 1, 2032; or (iii) co-fire with natural gas (40%) beginning January 1, 2030, and retire by January 1, 2039.

Because there are uncertainties surrounding the 111 GHG Rules, such as ongoing legal challenges, state plan development, and feasibility of compliance timelines, the ultimate implementation of the Rules is uncertain. However, the final 111 GHG Rules remain in place during this review. Accordingly, the Company's scenario planning includes two possibilities—one where the rules remain in effect and one where they do not. Three of the nine scenarios use views where the 111 GHG Rules are in effect, while the remaining six scenarios use views where the 111 GHG Rules do not remain in effect. This approach accounts for this uncertainty and incorporates appropriate flexibility to its compliance strategy.

**Q. WHICH SCENARIO IS CONSIDERED THE COMPANY'S BASE CASE?**

A. The Company's base case is Scenario 1 – 111-MG0, which assumes a moderate gas, zero-dollar carbon view with the 111 GHG Rules in effect.

**Q. WHY DID THE COMPANY MODEL THESE SPECIFIC SCENARIOS?**

A. As the energy industry experiences rapid change on numerous fronts (*e.g.* technology, fuel costs, regulatory changes), the Company continues to utilize a scenario planning process that provides for maximum flexibility, optionality, and innovation. While these scenarios cannot address every future possibility, they address sufficient futures to ensure the Company can provide reliable and affordable service even if the future is different than the Company forecasts today.

**Q. HOW ARE THESE SCENARIOS USED IN THE COMPANY'S IRP ANALYSES?**

A. Collectively, the nine planning scenarios provide a framework for the Company to evaluate its options and make resource planning decisions. The scenarios are used in the analyses supporting the 2025 IRP, including but not limited to the resource mix study, unit retirement studies, unit upgrade analyses, and DSM analyses. Not every scenario is used in each analysis, but all nine scenarios are available for use, as applicable.

### *B. Resource Mix Study and Expansion Planning*

**Q. WHAT IS THE PURPOSE OF THE RESOURCE MIX STUDY AND THE GENERIC EXPANSION PLANS?**

A. The Company's expansion planning analysis identifies the economically optimal mix of resources that reliably meet future capacity and energy demands. In this step of the planning process, demand-side resources are integrated with supply-side resources to provide a roadmap that informs long-term resource planning decisions. Significantly, generic expansion plans do not represent a resource planning decision by the Company but rather are indicative of what may be an optimal mix of resources within various future scenarios. The results of generic expansion plan modeling are combined with the existing fleet of resources as inputs into more detailed production cost modeling to produce hourly avoided energy costs for each scenario. Using this information, the Company performs resource-specific economic evaluations for both demand-side and supply-side options. When Georgia Power evaluates actual resources to meet the capacity needs identified in the IRP, the generation resources procured will be selected in accordance with the Commission's RFP rules. Thus, the purpose of the expansion planning process is to evaluate capacity and energy resource *options* to meet the Company's identified capacity need across a wide range of potential future scenarios.

## V. SUPPLY-SIDE STRATEGY

### *A. Overview*

**Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED SUPPLY-SIDE PLAN.**

A. For the 2025 IRP, Georgia Power employed a comprehensive supply-side strategy designed to enhance the reliability, flexibility, and value of resources for the benefit of customer needs. As described more fully below, the Company's diversified approach leverages economical extensions and enhancements to existing generating resources as well as new procurements, which are necessary to ensure reliable and economical service to customers and a growing Georgia.

In addition to the proposed continued operation of Plant Bowen Units 1–4, key elements of the Company's supply-side strategy include the following:

- Resource Extensions: Includes extending operation of six existing generating units to preserve operating capacity.
- Resource Upgrades: Includes upgrade projects for 14 existing gas and nuclear units.
- Hydro Modernization: Includes investment in 43 existing hydro units at nine plants.
- Renewable Procurement: RFPs designed to procure energy from up to 4,000 MW of renewable resources by 2035.

### *B. Resource Extensions & Continued Operation*

**Q. PLEASE DESCRIBE THE COMPANY'S REQUEST TO PRESERVE EXISTING OPERATING CAPACITY.**

A. The Company requests to preserve 1,007 MW of reliable, existing operating capacity by extending the operation of six generating units: Plant Scherer Unit 3; and Plant Gaston Units 1-4 and A. The Company seeks to extend the operation of Plant Scherer Unit 3 beyond December 31, 2028, assuming operation of this unit through the end of either 2035 or 2038, depending on the planning scenario. The Company requests to extend operation of Plant Gaston Units 1-4 and A beyond December 31, 2028, and assume operation through the end of 2034.

**Q. WHAT HAS CHANGED SINCE THE COMPANY RECOMMENDED NEAR-TERM RETIREMENT DATES FOR PLANT SCHERER UNIT 3 AND PLANT GASTON UNITS 1-4 AND UNIT A IN THE 2022 IRP?**

A. In the 2022 IRP, Georgia Power recommended the decertification and retirement of Plant Scherer Unit 3, Plant Gaston Units 1-4, and Unit A by December 31, 2028. These recommendations were based on the substantial economic benefits provided by the low-cost, valuable replacement generation identified in the 2022-2028 Capacity RFP, which was intended to meet the capacity needs driven by the planned retirement of coal units and the relatively low levels of load growth projected at that time. However, given the rapid expansion of economic development following the 2022 IRP, as recognized in the 2023 IRP Update, and further forecasted growth in this 2025 IRP, the Company's projected capacity needs require the extension of existing coal and gas-steam units in addition to the procurement of new capacity resources. Extending the operations of these existing generating units provides immediate economic value and efficiencies to the System, reducing the need to immediately construct new resources. Thus, the 2025 IRP updates the retirement dates for certain generating resources to ensure continued reliability and provide economic benefits for customers.

**Q. HOW DID THE COMPANY DETERMINE THAT EXTENDING OPERATION AT PLANT SCHERER UNIT 3 AND PLANT GASTON UNITS 1-4 AND UNIT A WAS IN THE BEST INTERESTS OF CUSTOMERS?**

A. The Unit Retirement Study in Technical Appendix Volume 1 includes an updated economic analysis that supports extending operation of these existing generating units. The analysis evaluates the economic implications of new environmental regulations, including the 2024 ELG Rule and the 111 GHG Rules as discussed further by Witnesses McNelly and Mitchell. The Unit Retirement Study compares the costs and benefits of the available environmental compliance pathways compared to the cost and timing of replacement alternatives. Given the Company's significant capacity needs and the costs associated with replacement generation, including the cost of supporting infrastructure such as transmission lines and natural gas pipelines, the continued operation of existing generating units with the compliance options recommended is more cost effective and poses lower risk than other pathways including retirement.

**Q. PLEASE DESCRIBE THE COMPANY'S REQUEST TO CONTINUE OPERATING BOWEN UNITS 1-4.**

A. In the 2022 IRP, the Commission deferred a decision on the retirement of Plant Bowen Units 1-2 to the 2025 IRP, with a potential retirement date as early as December 31, 2027.

Due to the significant increase in forecasted overall load growth since the 2022 IRP and 2023 IRP Update, the Company reevaluated its retirement recommendation for Plant Bowen Units 1-4 and is requesting to continue operating the units with necessary investments in environmental controls through at least 2035.

**Q. IS THE CONTINUED OPERATION OF BOWEN UNITS 1-4 IN THE BEST INTERESTS OF CUSTOMERS?**

A. Yes. The updated economic analysis included in Technical Appendix Volume 1 supports continued operation at Bowen Units 1-4 as a reliable and economical resource, even when considering the impacts of the 111 GHG Rules and 2024 ELG Rule. The Company plans to install ELG controls by December 31, 2029, as required to comply with the 2024 ELG Rule, which will preserve the ability to operate these units beyond 2034. Additionally, installing these ELG controls will provide Georgia Power with greater 111 GHG Rules compliance flexibility, enabling the natural gas co-fire compliance pathway to be selected during the state plan development process.

The co-fire compliance pathway permits operation until December 31, 2038, and defers the need for replacement capacity until 2039. This pathway is more optimal for customers than the other 111 GHG Rules compliance options and acknowledges that retirement by January 1, 2032, for these units is not practicable due to reliability and projected capacity needs. In addition, maintaining dispatchable generation in north Georgia is crucial for reliability. The continued operation of Plant Bowen Units 1-4 provides a reliable source of generation necessary to meet the needs of customers and maintain optionality and flexibility in the Company's environmental compliance strategy and long-term resource planning.

***C. <u>Gas Unit Upgrades</u>***

**Q. PLEASE DESCRIBE THE PLANNED UPGRADES AT MCINTOSH UNITS 10-11.**

A. The upgrade opportunity being evaluated and recommended for the combined cycles at McIntosh Units 10-11 is the General Electric ("GE") 7FA.05 upgrade. The scope of this upgrade includes replacing rotating blades and stationary vanes in the CTs (two CTs per combined cycle unit), combustor replacement, increasing firing temperature and shaft limits, and additional operating mode flexibility. This upgrade is projected to achieve an incremental capacity of 194 MW (winter). This enhancement increases the capacity of these existing combined cycle units while also improving the heat rate.

**Q. PLEASE DESCRIBE THE PLANNED UPGRADES AT MCINTOSH UNITS 1A-8A.**

A. The Company seeks to replace existing turbine components at McIntosh Units 1A-8A, which will allow each unit to operate at a higher capacity. The replacement components cost less than the in-kind replacement parts, which reduces the capital budget. This upgrade will provide an additional 74.4 MW (winter) of incremental capacity over a staggered schedule from 2026 to 2033. These upgrades are designed to provide additional economic peaking capacity, ensuring the existing plant can meet peak demand periods more effectively.

**Q. HOW DID THE COMPANY DETERMINE THAT UPGRADING THESE RESOURCES WAS IN THE BEST INTEREST OF CUSTOMERS?**

A. Along with the positive economic evaluation outcome detailed in the Unit Upgrade Analyses included in Technical Appendix Volume 1, these upgrades improve the efficiency of existing resources to deliver economical capacity during a time in which capacity resources are needed to support load. These projects benefit customers as they do not carry the risk associated with new site construction nor do they require a high level of transmission project investment.

***D. <u>Nuclear Unit Upgrades</u>***

**Q. PLEASE DESCRIBE THE PLANNED UPGRADES AT HATCH UNITS 1-2 and PLANT VOGTLE UNITS 1-2**.

A. The Company has proposed extended power uprates ("EPU") at Plant Hatch Units 1-2 and Plant Vogtle Units 1-2. These EPUs result in greater electrical power generation by increasing the thermal output of the nuclear reactors. Similar to the natural gas upgrades discussed above, these upgrades at existing nuclear units will provide additional capacity to serve customers without the expected need for a high level of incremental transmission system investments and without new site construction risks.

**Q. HOW DID THE COMPANY DETERMINE THAT UPGRADING THESE RESOURCES WAS IN THE BEST INTERESTS OF CUSTOMERS?**

A. As described in the Unit Upgrade Analyses in Technical Appendix Volume 1, the Company's economic analysis demonstrates that the proposed upgrades are cost-effective compared to the existing unit configurations, particularly with consideration for potential future customer subscription opportunities. Further, the upgrade investments are supported by both federal and state tax incentives such as the IRA-enabled production tax credits ("PTCs"), which would provide 10 years of benefit for the high-capacity factor achieved through these upgrades. These strategic upgrades leverage existing facilities and provide customers with economical, carbon-free baseload generation.

***E. <u>Hydro Modernization Investments</u>***

**Q. WHAT PROGRESS HAS GEORGIA POWER MADE ON ITS HYDRO FLEET MODERNIZATION PROJECTS SINCE THE 2022 IRP?**

A. To date, the Commission has approved seven hydro modernization projects, including Plant Terrora, Plant Tugalo, Plant Bartletts Ferry Units 1-4, Plant Nacoochee, and Plant Oliver in the 2019 IRP, as well as Plant Burton and Plant Sinclair in the 2022 IRP. Since then, the Company has continued making significant progress on each of these projects through the design, engineering, procurement, and construction of highly specialized hydro generation equipment.

The modernization project for Plant Terrora Units 1-2 was completed on time and under budget, with the units returning to normal operation in November 2021 and December 2020, respectively. Since the 2022 IRP, the modernization projects were completed for Plant Tugalo Units 1-2 in 2023—months ahead of schedule, leading to project cost savings.

The modernization project for Plant Tugalo Unit 3 was completed in 2024, and installation work is ongoing for Unit 4 with expected completion in the first half of 2025. Engineering and procurement activities have been completed for Plant Bartletts Ferry Units 1-4. Construction is ongoing at the site, where challenges associated with supply chain issues and the identification of more equipment wear and damage than anticipated are expected to result in overall delays to the project. Engineering and procurement processes are in progress for the remaining plants approved for hydro modernization, including Plants Burton and Sinclair. The Company has kept the Commission abreast of its progress on these units through bi-annual reports in Docket Nos. 42310 and 44160.

**Q. IS GEORGIA POWER REQUESTING APPROVAL FOR ADDITIONAL HYDRO INVESTMENTS IN THE 2025 IRP?**

A. Yes. The Company requests approval to complete the hydro modernization projects on its remaining hydro generating fleet, which includes:

- Plant Tallulah and Plant Yonah in the North Georgia Hydro Group;
- Plant Bartletts Ferry Units 5-6, Plant Goat Rock, and Plant North Highlands in the Chattahoochee Hydro Group;
- Plant Lloyd Shoals and Plant Wallace (including Units 1, 2, 5 & 6 Pumped Storage and Units 3-4) in the Central Georgia Hydro Group; and
- Plants Flint River and Morgan Falls.

Hydro modernization projects at these facilities include critical replacements and/or refurbishments needed for turbines, generators, and balance of plant equipment.

Maintaining, investing, and operating these emission-free hydro resources will preserve 665 MW of capacity for the benefit of customers. By completing these projects, the Company can better maintain and operate these emissions-free capacity resources, helping to fully optimize fleet operation and maximize fleet flexibility. The hydro modernization section of Technical Appendix Volume 1 includes the estimated capital costs, cost benefit analyses, and economic comparisons of alternatives to modernization and associated supporting materials.

**Q. PLEASE DESCRIBE GEORGIA POWER'S REQUEST TO DEVELOP, OWN, AND OPERATE INCREMENTAL CAPACITY AT PLANT GOAT ROCK UNITS 3-6.**

A. Georgia Power requests Commission authority to develop, own, and operate the increased capacity associated with turbine redevelopment to correct a flow imbalance in the Chattahoochee Hydro Group. The redevelopment of the turbines is expected to increase the capacity of each unit by approximately 4 MW, bringing the capacity of the entire Goat Rock hydro facility from approximately 39 MW to approximately 55 MW. This redevelopment will allow for maximizing water usage for economical energy production at Plant Goat Rock, as well as allowing for the most efficient operation of the associated river chain of hydro plants.

If this request is approved, the Company plans to complete further engineering and procurement to determine the optimal technology solution and design for these units. The Company will provide a certification amendment application for Commission approval once finalized.

**Q. HOW DID THE COMPANY DETERMINE THAT MODERNIZATION OF THE REMAINING NINE HYDRO FACILITIES WAS IN THE BEST INTERESTS OF CUSTOMERS?**

A. The Company performed a cost-benefit analysis and economic comparisons of alternatives to modernization for the requested sites. Specifically, the Company performed an economic analysis comparing hydro modernization at the requested sites to two alternative options: (1) removal of generation assets while maintaining the dam structure, known as the "unit retrofit" option; and (2) removal of generation assets and the dam structure, known as the "dam removal" option.

The unit retrofit option was eliminated because it was deemed impracticable to maintain a dam structure and allow for water flow without any generation. This option was not found to be a proven technology option for the hydropower industry. Further, the lack of generation under this option would likely risk the surrender of the plants' Federal Energy Regulatory Commission ("FERC") licenses, at which point the ownership, control, and regulation of the dam structure would become uncertain, creating unknown risks and unknown costs for Georgia Power's customers.

The dam removal option was evaluated for Plant Burton and all the remaining hydro facilities requested in this IRP and was found to be uneconomical in the cost-benefit comparison to hydro modernization. As demonstrated in the Company's Technical Appendix, the cost to remove the dam holds high uncertainty and could be up to 300% of base costs used in the analysis.[4] Additionally, these facilities are all licensed by FERC under the Federal Power Act, which requires license holders like the Company to make all necessary replacements to maintain facilities in a condition adequate for the efficient operation in the development and transmission of power. The FERC licenses associated with the remaining hydro plants are based on the facilities' ability to meet the power and water flow requirements contained in the license. If the generation cannot be maintained, the Company would be required to apply and receive approval for a FERC license surrender for a dam removal and its associated loss of generation.

Thus, modernization is needed to continue the operation of these hydro plants and to ensure compliance with the plants' FERC licensing. The equipment at these facilities is nearing the end of its service life and must be replaced or refurbished in order to maintain the plants' FERC licensing, which requires efficient generation and transmission of power. Technical Appendix Volume 1 includes estimated capital costs for the Hydro

[4] *See* Technical Appendix Vol. 1, Hydro Modernization, Table 3.

Modernization projects for the remaining nine hydro plants, as well as the required cost-benefit analysis supporting the investments.

**Q. IS MODERNIZATION THE MOST ECONOMICAL OPTION FOR ALL NINE HYDRO PLANTS?**

The economic analysis shows that modernization is the most economical option for all newly requested projects, except for Plant Morgan Falls. Plant Morgan Falls provides several qualitative benefits, and the Company requests approval of the Plant Morgan Falls modernization project to keep that facility operational for multiple ongoing benefits that are in the best interest of customers. As the Company's oldest hydro plant, two of the seven units at Plant Morgan Falls are already out of service due to equipment failures, so modernization is required to bring these units back into service. Further, water releases from Plant Morgan Falls are among the main water supply sources for metro Atlanta, and agreements with the Atlanta Regional Commission require water levels at Plant Morgan Falls to be sufficiently maintained to meet Atlanta's water needs. Finally, Plant Morgan Falls provides recreational and community benefits through its location on federal lands within the Chattahoochee River National Recreation Area. In short, Plant Morgan Falls is crucial to both Atlanta's water supply and the local community. Thus, the approval of all nine hydro modernization projects, including for Plant Morgan Falls, yields economic and qualitative benefits for Georgia Power Customers. Accordingly, the Company seeks approval for all nine newly requested modernization projects.

**Q. WHY IS IT BENEFICIAL FOR THE COMMISSION TO APPROVE MODERNIZATION FOR ALL NINE REMAINING HYDRO FACILITIES?**

Modernization of all remaining units in the hydro fleet provides several key benefits to Georgia Power customers. The sooner that modernization is completed, the sooner the Company will be able to fully gain the benefits of enhanced fleet dispatch and operational efficiencies at each river chain. Approval will also provide the Company with greater flexibility to address sites with the most pressing needs and mitigate extended outages as conditions change among the fleet; this particular benefit will positively impact the overall modernization schedule. Additionally, approval will maximize flexibility and efficiency related to supply chain, permitting, and labor force challenges and clean energy incentives such as grant and loan opportunities. Importantly, approval of the remaining facilities will allow the Company to effectively retain and utilize a workforce that is trained and experienced in these types of upgrades, thereby improving the Company's ability to successfully and efficiently modernize its remaining units.

### ***F.*** ***Capacity RFP***

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ALL-SOURCE CAPACITY RFP.**

A. The Company plans to issue an All-Source Capacity RFP in the third quarter of 2025 to meet its capacity need through 2032 and 2033. The target capacity range to be procured through this RFP will be determined based on the Company's capacity needs at the time the RFP is issued, which will be informed by the outcome of this 2025 IRP and the results of the Company's active capacity RFPs, with the ultimate amount of capacity procured to be determined at the time of certification of the resources resulting from the RFP.

Subsequent capacity RFPs for needs beyond 2032 and 2033 will be brought to the Commission for approval based on the required lead time for the RFP process plus construction of any new-build generation and transmission assets.

## VI. TRANSMISSION AND INNOVATIVE SOLUTIONS

**Q. PLEASE DESCRIBE GEORGIA POWER'S TEN-YEAR TRANSMISSION PLAN FILED IN THE 2023 IRP UPDATE.**

A. The 2025 IRP includes the 2024 Georgia ITS Ten-Year Plan, which incorporates generation and load growth updates for Georgia Power, the Georgia Transmission Corporation ("GTC"), the Municipal Electric Authority of Georgia ("MEAG Power"), and Dalton Utilities (collectively, the "ITS Participants"). This Ten-Year Plan, which has been filed annually pursuant to the Commission's Order in the 2022 IRP, includes changes since the 2022 IRP and 2023 IRP Update. As a complement to the Ten-Year Plan, the 2025 IRP also includes a comprehensive bulk transmission plan of the Georgia ITS summarizing studies, project lists, processes, data files, and other information required by the amended Commission Rules adopted by the Commission in Docket No. 25981.

**Q. PLEASE ELABORATE ON THE REGIONAL COLLABORATION AND COORDINATION THAT INFORMS THE TRANSMISSION PLANNING PROCESS.**

A. Sections A, B, and D, and E1 of Technical Appendix Volume 3 detail the Georgia ITS and Southeast Regional Transmission Planning ("SERTP") planning processes. These examples demonstrate how the Company is involved in robust collaborative transmission planning processes. For example, the SERTP planning process provides an open and transparent transmission planning forum for transmission providers to engage with stakeholders regarding transmission plans in the region.[5] Stakeholders such as developers and Staff regularly attend the quarterly SERTP meetings, during which they can provide input on transmission plans. Information on how to participate in the meetings is posted publicly on the Company's OASIS website and through the SERTP website.

***A. Strategic Transmission***

**Q. PLEASE DISCUSS THE COMPANY'S STRATEGIC TRANSMISSION PLANNING PROCESS.**

A. The consideration of transmission system impacts when making generation resource decisions is a key aspect of the IRP. The Company routinely takes these considerations into account by completing transmission evaluations separate from and incremental to the standard ten-year transmission planning processes. For example, the Company's

[5] SERTP includes the following sponsors: Southern Company, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company, Associated Electric Cooperative Inc., the Tennessee Valley Authority, and Duke Energy (Duke Energy Carolinas, LLCs and Duke Energy Progress, Inc.).

transmission planning process includes identification of strategic transmission projects that are included in this filing. These projects are also developed through the joint planning efforts with other ITS Participants to identify effective solutions that lessen the impact to the transmission system while projects are under construction.

**Q. WHAT STRATEGIC TRANSMISSION INVESTMENTS ARE ADDRESSED IN THE 2025 IRP?**

A. Since the 2022 IRP, Georgia Power, in conjunction with the other ITS Participants, developed and initiated the projects in Table 11.3 of the 2025 IRP Main Document. Transmission projects listed in Table 11.3, which were first identified and included in the 2021, 2022, and 2023 Georgia ITS Ten-Year Plans, were identified and selected to improve power transfer from South Georgia to North Georgia (formerly known as the North Georgia Reliability & Resiliency Action Plan), while preparing the transmission system for generation fleet transitions. In contrast, transmission projects listed in Table 11.3 that were first identified and included in the 2024 Georgia ITS Ten-Year plan were selected primarily to accommodate load growth and generation additions while maintaining System reliability.

**Q. HOW WILL THE COMPANY APPROACH STRATEGIC TRANSMISSION PLANNING GOING FORWARD?**

A. Georgia Power will implement additional planning considerations and process enhancements beyond the ten-year transmission planning horizon described above to address long-lead integrated system projects. It is becoming more common in the utility industry to extend the planning horizon beyond ten years. This longer-term planning horizon will allow the necessary lead time to both identify and execute the most effective solutions that appropriately balance local and regional considerations. Moreover, System needs and growth continue moving at an extraordinary pace. Therefore, the Company plans to integrate a more strategic planning approach to expand transmission capacity with local future siting considerations going forward.

**Q. DID THE COMPANY USE THIS EXTENDED HORIZON FOR STRATEGIC TRANSMISSION PROJECTS INCLUDED IN THE 2025 IRP?**

A. No. Georgia Power will implement the extended horizon in future planning cycles.

## *B. Innovative Transmission Solutions*

**Q. PLEASE DISCUSS THE INNOVATIVE TRANSMISSION SOLUTIONS THAT THE COMPANY CONSIDERS AND DEPLOYS THROUGHOUT THE TRANSMISSION PLANNING PROCESS.**

A. The Company remains committed to exploring and implementing a diverse portfolio of solutions to both meet customer needs and ensure grid reliability in a cost-effective manner. For example, the Company continues deploying innovative transmission solutions using grid-enhancing technologies ("GETs"), where these technologies are safe, reliable, and economical. The Company also deploys other innovative solutions, including non-wires alternative ("NWA") solutions. Although there is some overlap between GETs and NWA solutions, GETs can be deployed in a variety of circumstances, including wires-based solutions.

**Q. WHAT ARE "GETs"?**

A. GETs refer to a portfolio of technologies focused on increasing grid capacity and enabling the further reliable integration of inverter-based generation resources. Consistent with the Electric Power Research Institute, the Company defines GETs across four primary technology categories: Advanced Conductors; Advanced Power Flow Control; Topology Optimization; and Adaptive Line Ratings. The Company also includes flexible AC transmission systems technologies in the GETs portfolio.

Georgia Power will continue exploring all opportunities to defer the need for transmission upgrades to accommodate future load growth and proposed generation additions by deploying GETs and other innovative solutions.

**Q. ARE THERE OTHER INNOVATIVE TECHNOLOGY SOLUTIONS REQUIRED TO SUPPORT GRID RELIABILITY THAT ARE INCLUDED IN THE 2025 IRP?**

A. Yes. Georgia Power was previously approved to begin preliminary steps to invest in a Distributed Energy Resource Management System ("DERMS") to prepare the grid for increasing levels of DER penetration. Enhanced control of DERs will enable the Company to leverage DERs to ensure optimal grid operation. Specifically, having enhanced control of DERs through DERMS further supports grid reliability and expands potential use cases for DERs that can be reflected in customer program incentive valuations. These programs are further described in Customer Programs Panel Direct Testimony.

**Q. WHAT SPECIFIC APPROVALS RELATED TO DERMS WERE GRANTED IN GEORGIA POWER'S 2022 RATE CASE, AND HOW HAVE THEY SHAPED THE COMPANY'S APPROACH TO DERMS IMPLEMENTATION IN THE 2025 IRP?**

A. The Commission's Order in Georgia Power's 2022 Rate Case authorized the Company to move forward with preliminary steps to support the development and deployment of a DERMS for the purposes of gaining visibility and forecasting of DERs. This approval allowed Georgia Power to begin investing in the necessary infrastructure, software, and operational frameworks to integrate DERs into grid operations. However, to more fully take advantage of customer DER programs and optimize dispatchable customer-sited resources for grid reliability, the Company is requesting approval for enhanced control capabilities of DERs through its DERMS.

**Q. WHAT SPECIFIC CAPABILITIES WILL GEORGIA POWER'S DERMS PLATFORM PROVIDE TO SUPPORT THE INTEGRATION OF DERS?**

A. Georgia Power's DERMS will provide visibility, modeling, and control of DERs, enabling the Company to leverage DERs and optimize operations across asset types and use cases based on System needs. DERMS will be capable of forecasting DER generation, managing grid constraints, and coordinating DER output to enhance System reliability. It will also allow for automated responses to grid disturbances by adjusting DER contributions, ensuring they can provide grid support services efficiently. To achieve these outcomes, DERMS will facilitate communication between Georgia Power's grid operations and various DER assets both Company- and customer-owned, such as battery storage, customer-sited solar, and demand response resources like those described in the Customer Programs Panel.

**Q. HAS THE COMPANY PURSUED STATE OR FEDERAL FUNDING OPPORTUNITIES FOR TRANSMISSION-RELATED INVESTMENTS?**

A. Yes. The Company continues to seek alternate sources of funding where applicable to minimize cost impacts to customers, including transmission system investments. In fact, Georgia Power has been conditionally awarded approximately $160 million of grant funding through the DOE's Grid Resilience and Innovation Partnerships (GRIP) program. This grant focuses on the deployment of innovative solutions through new GETs on the Company's transmission grid, specifically through the deployment of advanced conductor and dynamic line rating technologies.

In addition, Georgia Power is currently pursuing DOE Title 17 loan opportunities that support Energy Infrastructure Reinvestment. The outstanding funding requests include a portion of the transmission investments included in the Company's portion of the Georgia ITS Ten-Year Transmission Plan, strategic transmission projects, and continued deployment of innovative solutions like GETs.

At the state level, Georgia Power is also pursuing state-administered funding opportunities. For example, the Company applied for funding through the Grid Resilience grant program administered by the Georgia Environmental Finance Authority (GEFA). If selected for funding through this program, Georgia Power's proposal will be subject to further review and negotiations with the DOE. The Company will continue to seek funding opportunities to minimize costs to customers as part of the commitment to provide clean, safe, reliable, and affordable electric service.

## VII. WHOLESALE TO RETAIL CAPACITY

**Q. WHY IS THE COMPANY OFFERING WHOLESALE CAPACITY TO RETAIL CUSTOMERS?**

A. The Commission's July 30, 2008, Order in Docket No. 26550 required Georgia Power to offer certain wholesale capacity blocks to the retail jurisdiction on then-current wholesale market terms (the "Wholesale Action Plan"). Previous wholesale capacity blocks were offered under this arrangement and accepted or rejected by the Commission. However, in its July 21, 2022 Order in Docket No. 44160, the Commission determined that the Company had fulfilled the requirements of Docket No. 26550 and was no longer required to offer wholesale capacity to retail jurisdictions. The Commission further acknowledged that the Company could, at its discretion, offer wholesale capacity back to the retail jurisdiction.

Since the 2022 IRP, the Company's load forecast and corresponding capacity needs have changed, as have its plans for continued operations for Plant Scherer Unit 3. Therefore, the wholesale capacity offer proposed in this 2025 IRP will help fulfill a portion of the Company's capacity needs in the near term, and the proposed offer is consistent with the mandates of the Wholesale Action Plan.

**Q. PLEASE DESCRIBE THE WHOLESALE CAPACITY OFFER INCLUDED IN THE 2025 IRP.**

A. Georgia Power seeks to certify approximately 187 MW of capacity from Plant Scherer Unit 3 offered in four wholesale blocks pursuant to the terms and conditions offered in this filing. This capacity is made available to the retail jurisdiction pursuant to the Wholesale Action Plan, though the Company has previously met all requirements. The Wholesale Action Plan provided that certain wholesale capacity blocks would be offered to the retail jurisdiction (1) on terms equivalent to that which the Company could obtain in the then-current wholesale market, (2) in a manner that would not adversely affect the Company's ability to continue to sell such resources into the wholesale market, and (3) in a manner that the RFP process is not adversely affected.

**Q. HOW MUCH OF THE AVAILABLE WHOLESALE CAPACITY TO RETAIL IS THE COMPANY OFFERING IN THIS IRP?**

A. Georgia Power's offer of approximately 187 MW of wholesale capacity is consistent with the mandates of the Commission-approved Wholesale Action Plan. The initial offer of 52 MW is a partial block offer available January 1, 2026. An additional approximate 55 MW will become available January 1, 2030, followed by another approximate 55 MW on January 1, 2031, and a final approximate 25 MW on June 1, 2031.

Additional information on the Company's Wholesale to Retail offer can be found in Technical Appendix Volume 1.

**Q. HOW DOES GEORGIA POWER VALUE OR PRICE THE CAPACITY BEING OFFERED TO RETAIL JURISDICTION?**

A. Consistent with prior wholesale offers, Georgia Power proposes to use the Commission-approved application of a Market Differential Adjustment ("MDA") to meet the requirement that the transaction be offered at then-current wholesale market terms. The MDA represents the difference between the levelized market value and the levelized revenue requirement of the net asset over its remaining useful life, expressed on a dollar per kilowatt-month basis.

**Q. IS THE COMPANY ALSO SEEKING TO CERTIFY THIS CAPACITY AND INCLUDE IT IN RATE BASE?**

A. Yes. If the Commission accepts the Company's offer of 187 MW of wholesale capacity, Georgia Power also asks that it be certified. If certified, this offer provides for the entirety of the accepted wholesale capacity to be brought into the retail cost of service.

The assets would be placed in retail rate base at their current book value, accompanied by an MDA. To ensure the proper allocation of the MDA to the retail jurisdiction, the MDA will be treated as an adjustment to retail base revenues available for regulatory purposes, thereby resulting in an adjustment in retail base revenue requirements. As with other generating assets in retail rate base, all prudently incurred actual fuel costs associated with the resources will be recovered through the Fuel Cost Recovery process.

**Q. WHAT VALUE WILL PROCURING THESE 187 MW BRING TO CUSTOMERS?**

A. These 187 MW provide a reliable source of capacity and energy from existing resources for Georgia Power customers at a cost-effective market price during a time of capacity need. This will also avoid the need to invest in new site or transmission construction projects.

## VIII. CONCLUSION

**Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN THE 2025 IRP?**

A. The Company seeks approval of its 2025 IRP as proposed, including the associated specific requests listed in the Executive Summary of the Main Document, which includes actions necessary for the Company to continue to provide clean, safe, reliable, and affordable electric service for its retail customers.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

**STATE OF GEORGIA**

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

| | | |
|---|---|---|
| **Georgia Power Company's 2025 Integrated Resource Plan** | ) ) | **Docket No. 56002** |
| **Georgia Power Company's 2025 Application for the Certification, Decertification, and Amended Demand-Side Management Plan** | ) ) ) ) | **Docket No. 56003** |

**DIRECT TESTIMONY OF**

**JENNIFER S. MCNELLY AND ROBERT W. MITCHELL, III**

**FEBRUARY 28, 2025**

**DIRECT TESTIMONY OF**
**JENNIFER S. MCNELLY AND ROBERT W. MITCHELL, III**

**IN SUPPORT OF GEORGIA POWER COMPANY'S**
**2025 INTEGRATED RESOURCE PLAN**
**DOCKET NO. 56002**

**AND**

**APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND SIDE MANAGEMENT PLAN**
**DOCKET NO. 56003**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.**

A. My name is Jennifer S. McNelly. I am the Vice President of Environmental Affairs for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is Robert W. ("Brett") Mitchell, III. I am the Director of the Coal Combustion Residuals ("CCR") Program Management Office for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

**Q. MS. MCNELLY, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated from the University of Alabama with a Bachelor of Science in Chemical Engineering. I also completed a Master of Business Administration degree from the University of Alabama at Birmingham.

I have worked in a variety of roles within the Southern Company footprint since beginning my career in 2001 as a cooperative education student with Southern

Nuclear Company. In 2005, I began as an engineer at Southern Company Services ("SCS") where I was responsible for leading process design for large capital environmental projects. From 2011 to 2018, I worked in various leadership roles within Generation for both Alabama Power and Georgia Power, including maintenance and operations team leader roles at Plant Miller; the Assistant to the Senior Production Officer and Vice President of Generation; the Operations Department Assistant Manager at Plant Bowen; the Engineering, Compliance, and Support Manager at Plant McDonough; and the Maintenance Manager at Plant Bowen. In 2018, I transitioned to the Environmental Solutions Water Program Manager role at SCS. As Water Program Manager, I supervised ash process personnel and activities and participated in environmental strategy budget inputs, water treatment project processes, fleet-wide ash pond dewatering treatment, and vendor partnerships. In 2020, I served as the Director of Environmental Solutions at SCS. In that role, I led the Environmental Solutions Department, comprised of the Air Program, Water Program, Land Strategy, Earth Sciences & Environmental Engineering, and Geotechnical/Fossil Dam Safety.

I currently serve as the Vice President of Environmental Affairs at Georgia Power and have been in this role since March 2023. In this role I am responsible for the overall environmental compliance of business operations at the Company and regulatory obligations related to compliance with existing and anticipated environmental laws and regulations. This responsibility includes the creation and implementation of the Company's Environmental Compliance Strategy ("ECS") and supporting processes.

**Q. MS. MCNELLY, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?**

A. No.

**Q. MR. MITCHELL, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated from the University of Georgia with a degree in Environmental Health Sciences. I have worked at Southern Company since 1995, when I began my career at Georgia Power as an environmental specialist responsible for managing environmental remediation projects across the state. In 2007, I moved to a supervisory role overseeing all Georgia Power remediation and waste compliance activities, including assessing, selecting, and implementing site-specific remediation methods and technologies, overseeing environmental emergency response activities, permitting landfills to support operations and the installation of environmental controls, and managing special wastes to ensure proper disposal. I transitioned to Southern Company from 2014 to 2016 as the Conceptual Engineering Manager responsible for strategy budget inputs, and developing strategies to address land and water related environmental requirements for all operating companies, including for the CCR Rule. In 2016, I returned to Georgia Power to manage the team leading the company's CCR compliance strategy development and implementation, including for the federal and newly finalized state CCR rule and permitting program. During this time, I was also responsible for managing Georgia Power's ongoing remediation and waste compliance programs. In 2020, I served as CCR Portfolio General Manager responsible for Georgia Power's CCR program strategy and execution. During this time, I was also responsible for standing up a Program Management Office and associated processes to proactively manage the large-scale and decades-long CCR program.

Currently, as the Director of the CCR Program Management Office for Georgia Power, I am responsible for the successful execution, governance, oversight, strategy, regulatory processes, and overall management of Georgia Power's CCR Program for ash pond and landfill closure projects. This includes direct oversight and management of all aspects of the closure of the Company's ash ponds, construction, operations, and closure of the CCR landfills at 12 current and former generation plant sites.

**Q. MR. MITCHELL, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?**

A. No.

**Q. WHAT IS THE PURPOSE OF THE PANEL'S TESTIMONY?**

A. The purpose of our testimony is to support the Company's ECS filed as part of Georgia Power's 2025 Integrated Resource Plan ("IRP"). We address specific aspects of the ECS, including recent regulatory and strategy updates related to greenhouse gas ("GHG") emissions limitations on fossil-based generation, Mercury and Air Toxics Standards ("MATS") revisions, Effluent Limitations Guidelines ("ELG") rules for scrubber wastewater and combustion residual leachate ("CRL"), and the state and federal CCR rules. In addition, our testimony discusses the Company's management of ash pond closure plans approved in the 2019 and 2022 IRPs, beneficial use of CCR, and Georgia Power's approach to planning for carbon pressures on its generating fleet.

**Q. PLEASE SUMMARIZE THE PANEL'S TESTIMONY.**

A. Georgia Power's ECS describes the comprehensive strategy to comply with all applicable state and federal environmental laws and regulations through the implementation of cost-effective environmental controls and actions. The strategy enables Georgia Power to develop a flexible and adaptive plan to ensure continued compliance and resource planning optionality.

Georgia Power continues to manage numerous regulatory requirements associated with its generation plants. Revisions to the Company's 2025 ECS reflect changes to environmental regulations finalized since the Georgia Public Service Commission ("Commission") previously approved the Company's ECS in the 2022

IRP. As such, the Company is focused on the investment and actions needed to comply with recent revisions to several key environmental regulations, including United States Environmental Protection Agency's ("EPA") 111 GHG Rules and the 2024 ELG Rule.

Notwithstanding pending legal challenges to each of the main environmental rules discussed herein, the Company must move forward on compliance actions with near-term compliance deadlines approaching. Further, since this uncertainty is likely to continue for the foreseeable future, it is imperative that the Company continue to take a long-term approach to planning decisions, building in appropriate flexibility and resource planning optionality, to ensure compliance readiness while continuing to meet customer needs.

For example, the 111 GHG Rule sets forth designated compliance pathways for existing steam generating units, with options to retire, install and operate carbon capture and sequestration ("CCS") technology, or co-fire coal with natural gas. It sets forth designated compliance pathways for new combustion turbines with options to install CCS or operate at less than 40% annual capacity factor. As discussed in the IRP Main Document, the ECS, and the Direct Testimony of Witnesses Grubb, Hubbert, Looney, Robinson, and Valle, the Company assumes all new combined cycle units will be limited to no more than a 40% annual capacity factor and has elected the co-fire compliance pathway for Plants Bowen and Scherer.

Further, EPA's 2024 ELG Rule requires the installation of additional wastewater treatment controls at current and former coal-fired power plants even though implementation of the 2020 ELG Rule is still in progress. The 2024 ELG Rule requires Zero Liquid Discharge ("ZLD") by December 31, 2029, for scrubber wastewater and leachate collected from on-site landfills at operational plants and additional treatment requirements for leachate and legacy water at retired sites. While ELG compliance plans at Plant Scherer are less impacted—due to the selection of the Voluntary Incentives Program ("VIP") compliance option for scrubber wastewater that remains unchanged from the 2020 ELG Rule—the new ZLD requirement presents a significant compliance challenge for Plant Bowen, where additional controls must be designed, engineered, and installed to comply.

Finally, the Company continues to make progress on its CCR compliance strategy to permanently close CCR ash ponds and landfills under the oversight of the Georgia Environmental Protection Division's ("EPD") federally approved CCR program. The Company continues to evaluate opportunities to refine and optimize its closure plans and pursue opportunities to create value through beneficial use.

The 2025 ECS describes the Company's plans to comply with environmental laws and regulations by implementing a strategic and flexible plan that installs cost-effective and protective controls consistent with the Company's commitment to supply clean, safe, reliable, and affordable energy to its customers. The Company requests Commission approval of the ECS and the related capital, operations and maintenance ("O&M"), and CCR asset retirement obligation ("ARO") costs, and associated measures taken to comply with government-imposed environmental mandates.

**Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?**

A. The remainder of our testimony is organized as follows:

- Section II provides an overview of the Company's Environmental Compliance Strategy.
- Section III discusses recent changes to applicable environmental compliance regulations.
- Section IV discusses the Company's CCR compliance strategy.
- Section V details Georgia Power's beneficial use activities.
- Section VI discusses climate and carbon pressures.

## II. ENVIRONMENTAL COMPLIANCE OVERVIEW

**Q. WHAT IS THE ENVIRONMENTAL COMPLIANCE STRATEGY?**

A. In accordance with Commission Rule 515-3-4-.04(1)(c), Georgia Power's ECS includes a detailed overview of the applicable current and proposed environmental laws and regulations for its electric generation plants as well as the Company's comprehensive strategy for complying with those requirements. The Company's annual ECS development process considers plant-specific compliance options and evaluates those options based on technology availability; cost; schedule; and impact to plant operations, the environment, and surrounding communities. This approach provides the necessary flexibility to develop and refine Georgia Power's ECS in today's dynamic regulatory compliance environment, assuring compliance with robust control plans that are in the best interests of customers.

**Q. PLEASE DESCRIBE THE ENVIRONMENTAL REGULATORY FRAMEWORK APPLICABLE TO GEORGIA POWER AND HOW THE ECS ENSURES COMPLIANCE WITH THAT FRAMEWORK.**

A. Georgia Power's ECS contains actions necessary to comply with federal and state requirements of multiple regulators, including the EPA, the Georgia EPD, and the Commission. The EPA creates, maintains, and enforces national standards under a variety of environmental laws and establishes these standards through the development of federal regulations. The Georgia EPD is the implementing body for both federal and state laws through rules, policies, and permits to protect human health and the environment. Finally, the Commission reviews the Company's ECS, along with the cost estimates to implement that strategy, and determines if the strategy and associated costs are reasonable.

The annual development of the ECS, in coordination with the triennial IRP process, provides an opportunity for the Company to respond to changing environmental regulations and incorporate new information as it becomes available over the course of Georgia Power's long-term planning process. While the strategy itself will necessarily evolve over time to address changes in applicable state and federal regulations, the purpose of the ECS process is and has always been to assure compliance with all environmental requirements, produce cost-effective compliance solutions that minimize the impact to customers, and to maintain the necessary flexibility to adjust to the dynamic nature of environmental regulations.

**Q. WHAT ARE SOME OF THE COMPANY'S MILESTONE ACHIEVEMENTS WITH REGARD TO ENVIRONMENTAL COMPLIANCE?**

A. Georgia Power is committed to meeting its environmental compliance obligations while also providing customers with clean, safe, reliable, and affordable energy. For example, since 1990, the Company has reduced nitrogen oxides ("$NO_x$") and sulfur dioxide ("$SO_2$") emissions from its generating fleet by more than 95% and 99%, respectively. Additionally, mercury emissions have decreased by more than 98% and carbon dioxide ("$CO_2$") emissions by more than 60% since 2007. Further, water withdrawals have decreased by 90% since 2003 with the transition of the generation fleet.

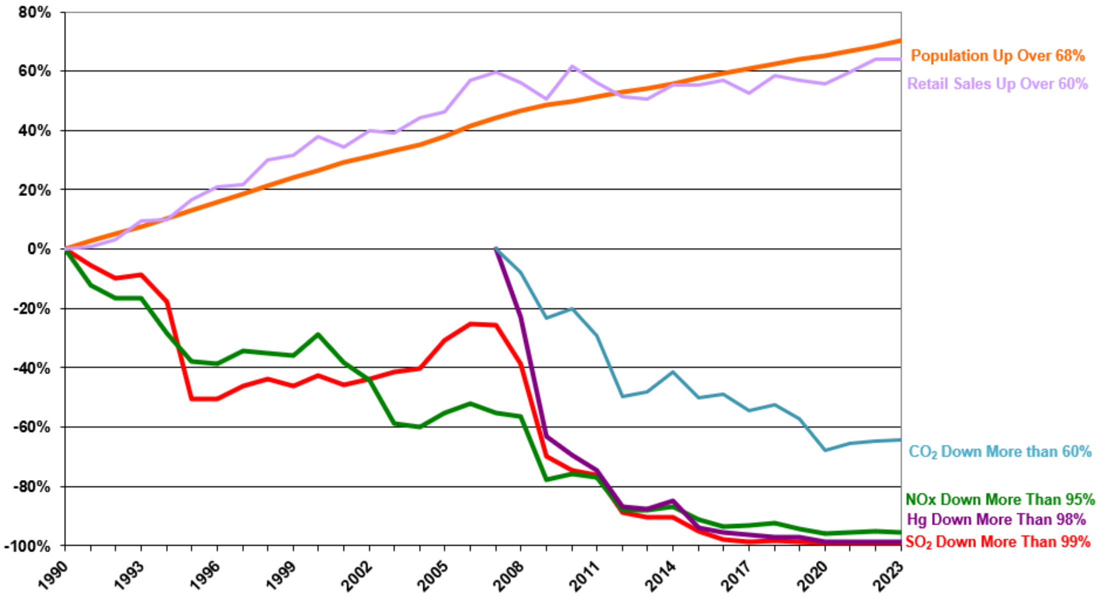


**FIGURE 1 – Georgia Power Emission Trends**

Requirements related to wastewater discharge and ash pond closures have resulted in the installation of 16 wastewater treatment systems and dry or zero discharge ash handling equipment for coal facilities. In compliance with the federal and state CCR rules, Georgia Power has advanced closure construction activities in various stages at its 29 ash ponds, which includes conducting preliminary sitework, design, dewatering, and closure construction.

Additionally, the Company continues to recycle, on average, more than 85% of the CCR generated from plant operations for beneficial use, which significantly reduces waste streams for the benefit of customers and the environment. As a part of ash pond closure, up to nineteen million tons of ash are anticipated to be harvested, processed, and removed from sites for beneficial use throughout the multi-year closure timeframe.

**Q. PLEASE DESCRIBE GEORGIA POWER'S 2025 ENVIRONMENTAL COMPLIANCE STRATEGY.**

A. Georgia Power's 2025 ECS sets forth a comprehensive strategy outlining the Company's cost-effective plans to comply with all applicable environmental requirements, including the following four rules finalized by EPA in the spring of 2024 that impose new requirements on utilities in the power sector: (a) GHG emissions limitations pursuant to the Clean Air Act, Section 111 ("111 GHG Rules"); (b) revised MATS; (c) revised and supplemental ELGs; and (d) CCR rule amendments through the Legacy CCR Surface Impoundments Rule ("Legacy Rule"). Each of these four environmental regulations are discussed in more detail below.

**Q. IS THERE REGULATORY UNCERTAINTY THAT COULD AFFECT THE 2025 ENVIRONMENTAL COMPLIANCE STRATEGY?**

A. Yes. Georgia Power's 2025 ECS accounts for uncertainty in legal and regulatory outcomes related to the new rules finalized by EPA in 2024. While all four of the new rules have been legally challenged, in each case the respective court declined to put the rule requirements on hold. As such, all the rules remain in effect with compliance deadlines quicky approaching. The Company's compliance strategy for these new rules ensures environmental mandates can be met while remaining ready to adapt to future litigation or regulatory developments. The final outcomes of ongoing litigation, potential executive actions, and potential subsequent rulemaking may take years to resolve, and this uncertainty requires that Georgia Power work towards compliance with final regulations, as implemented by EPD through its permits and state plan, while staying flexible for various outcomes, including the suspension of some or all rule requirements. Therefore, the Company will continue its current compliance strategy until there is more certainty on the ultimate outcome for each challenged regulation, at which time the Company will reevaluate and adapt the ECS as appropriate.

The Company's "all of the above" approach to supply-side, demand-side, and transmission planning is critical to manage the uncertainty presented by environmental mandates both now and in the future, especially during a time of high projected load growth. The goal of the Company's strategy is to ensure compliance with all applicable state and federal requirements and provide cost-effective solutions for the generating fleet that are in the best interests of customers, while preserving the flexibility of the approaches taken given the dynamic regulatory environment.

## III. CHANGES TO ENVIRONMENTAL COMPLIANCE REGULATIONS SINCE 2022 AFFECTING THE ECS

### A. 111 GHG Rules

**Q. PLEASE DESCRIBE THE 111 GHG RULES AND WHAT THEY REQUIRE.**

A. The EPA's 111 GHG Rules seek to limit GHG emissions from power plants, with the 2024 rules specifically focused on new gas turbines and existing coal plants. As a result of the new requirements, by 2032 new combined-cycle units without CCS must limit their annual capacity factor to 40%. New simple-cycle combustion turbines ("CTs") must limit their annual capacity factors to no more than 40% and potentially as low as 20%. On the other hand, existing coal-fired generation units would be subject to standards set in a forthcoming state plan. EPA's Rule outlines three compliance pathways for existing coal units to states: (1) retirement by January 1, 2032; (2) add 90% CCS by January 1, 2032; or (3) 40% gas co-firing by January 1, 2030, with retirement by January 1, 2039. State plans are due May 2026 and are subject to EPA review and approval. The 111 GHG Rules permit states to deviate from these pathways if justified and needed.

**Q. WHAT IS THE COMPANY'S COMPLIANCE STRATEGY FOR THE 111 GHG RULES?**

A. Notwithstanding pending legal challenges to the 111 GHG Rules, Georgia Power must evaluate these regulations as currently finalized and develop compliance strategies. Certain affected generating units, including new CTs (Plant Yates Units 8-10) and existing steam generating units—Plant Yates Units 6-7 and Plant Gaston Units 1-4—are expected to be able to continue operating as planned and without significant additional cost or constraint under the new requirements. However, Plant Bowen Units 1-4 and Plant Scherer Units 1-3, comprising over 4,000 megawatts of capacity, are significantly impacted under the current 111 GHG Rules.

Two of the three pathways for coal units outlined in EPA's 111 GHG Rules, retire by January 1, 2032, or install and operate CCS, are not only costly but also impractical. Georgia Power's elected compliance strategy for all seven existing coal units is to pursue co-firing natural gas beginning January 1, 2030, or as soon as feasible, with retirement of these units by January 1, 2039. This decision is supported by the Company's planning tools such as Unit Retirement Studies, included in Technical Appendix 1, and other scenario analyses, which indicate that co-firing is more cost effective, poses lower risk, and is more technically feasible than other pathways, including retirement.

**Q. WHAT COMPANY UNITS ARE SUBJECT TO A STATE PLAN AND HOW WILL FINAL STANDARDS BE DEVELOPED?**

A. Plant Yates Units 6-7, Plant Bowen Units 1-4, and Plant Scherer Units 1-3 are subject to the state-specific compliance plan to be prepared by Georgia EPD and submitted to EPA for approval. In the plan, Georgia EPD will establish performance standards for each of these generating units based on EPA's guidelines, which contain "presumptively approvable" standards for subcategories of existing coal and gas-steam resources. However, EPD will not submit its plan until May 2026, and approval from EPA is not expected to occur until July 2027. Plant Gaston Units 1-4, which are located in Alabama, will similarly be subject to a state plan developed by the Alabama Department of Environmental Management. Because states have not yet developed the plans to establish the standards, and those plans will be subject to EPA review and approval, significant uncertainty remains regarding the potential impact of the 111 GHG Rules if they remain in effect.

For Plant Bowen and Plant Scherer, the presumptively approvable emissions standard based on 40% natural gas co-firing and the January 1, 2030, compliance date requires further analysis, which is ongoing. Both the emissions standard and compliance date will be finalized through engagement with Georgia EPD during the state plan process, contingent on approval by EPA. The final emissions standards and compliance dates may differ from those in EPA's guidelines based on the consideration of Remaining Useful Life and Other Factors ("RULOF"). In considering RULOF, the state can establish a standard or compliance date that differs from EPA guidelines as needed to account for a facility's individual circumstances. Georgia Power is in the process of conducting engineering studies to evaluate technical considerations and operational impacts of co-firing natural gas for the generating units at Plant Bowen and Plant Scherer. These studies will be critical to inform the state plan development process.

**Q. HAS THE COMPANY PARTICIPATED IN LEGAL CHALLENGES TO THE 111 GHG RULES?**

A. Yes. A multi-state coalition, including Georgia, as well as numerous industry and interest groups have filed legal challenges to the 111 GHG Rules before the U.S. Court of Appeals for the D.C. Circuit. Georgia Power's parent company, Southern Company, is a member of the Electric Generators for a Sensible Transition, one of the industry groups that filed a legal challenge. In July 2024, the D.C. Circuit declined to stay the rules, which resulted in emergency stay petitions at the U.S. Supreme Court. In October, the Supreme Court denied the request for emergency stay. The D.C. Circuit held oral arguments on the challenge on December 6, 2024.

On February 19, 2025, the court granted EPA's request to pause the litigation for 60 days while the agency reviews the rule. Notwithstanding the ongoing litigation, the 111 GHG Rules as finalized in 2024 are the current rules in effect and must be considered by Georgia Power in its planning process.

**Q. HOW DOES THE ECS PROCESS ACCOUNT FOR POTENTIAL CHANGES TO THE 111 GHG RULES OR LEGAL UNCERTAINTY?**

A. As discussed above, the ECS is an iterative process that is designed to provide the Company with a flexible and responsive compliance strategy for applicable environmental rules and regulations. Georgia Power continues to monitor and evaluate developments in the 111 GHG Rules. As a part of Georgia Power's ECS, the 111 GHG Rules strategy for Plant Bowen and Plant Scherer is to pursue the natural gas co-firing compliance pathway, starting with engaging engineering firms to perform boiler studies to determine potential designs for adding natural gas co-firing capability. Georgia Power will also engage with Georgia EPD and other stakeholders on the feasible compliance timeline and requirements that will minimize the impacts to reliability and affordability for customers. While these activities can be paused or slowed down in the event of a future legal decision or policy change, waiting to start these activities could have profound consequences for resource planning in the event the rules are upheld.

### B. 2024 Mercury and Air Toxics Standards Revisions

**Q. WHAT ARE THE MERCURY AND AIR TOXICS STANDARDS?**

A. Finalized in 2012, the EPA's MATS rule is a technology-based rule that regulates hazardous air pollutants ("HAP"), including mercury, acid gases, and metallic HAP (via particulate matter emissions as a surrogate) from coal- and oil-fired electric generating units. Under the Clean Air Act, EPA is required to review and update the standards as necessary on a periodic basis.

**Q. PLEASE DESCRIBE THE RECENT MATS REVISIONS.**

A. In 2024, EPA finalized MATS revisions that significantly lowered the particulate matter limit applicable to coal-fired power plants. The revisions also require utilities to demonstrate compliance with the revised limit through continuous emissions monitoring as opposed to stack testing, which was allowed under the prior standards. The Company must comply with the MATS revisions by July 2027.

**Q. WHAT IS THE COMPANY'S MATS COMPLIANCE STRATEGY?**

A. Georgia Power has complied with MATS for about 10 years. Currently, the Company utilizes stack testing to confirm its units are compliant with particulate matter emissions limitations, which consistently shows the Company's coal-fired generating units (Plants Bowen and Scherer) are emitting at levels less than the more stringent limit finalized in the 2024 MATS revision. Thus, the Company does not anticipate the installation of additional controls to comply with the revised standards. Compliance will require the addition of new particulate matter continuous emissions monitoring for each of Plant Bowen Units 1-4 and Plant Scherer Units 1-3.

### C. 2024 ELG Rule

**Q. PLEASE PROVIDE AN OVERVIEW OF THE PREVIOUSLY APPLICABLE ELG RULES.**

A. In November 2015, EPA updated its steam electric ELGs for the first time since 1982 (the "2015 ELGs"). The 2015 ELGs established technology-based standards affecting coal ash management and set stringent limits for scrubber wastewater. The 2015 ELGs established a VIP for scrubber wastewater, which provided a later compliance deadline for plants able to meet even more stringent scrubber wastewater limits based on advanced evaporation technology.

Since the issuance of the 2015 ELGs, the requirements have changed multiple times either by court action or EPA rule changes. In October 2020, EPA finalized revisions to the ELGs (the "2020 ELG Rule"), which had important implications for the Company's strategy on scrubber wastewater treatment. For scrubber wastewater, the 2020 ELG Rule established standards based on wastewater treatment technology consisting of a combination of chemical precipitation followed by biological treatment (also referred to as physical-chemical-biological treatment or "phys-chem-bio") with a compliance deadline of December 31, 2025. Compared to the 2015 ELGs, the scrubber wastewater limits were slightly less stringent for certain constituents and significantly more stringent for others. The 2020 ELG Rule also revised the VIP subcategory for scrubber wastewater to provide a compliance deadline of December 31, 2028, for plants to achieve more stringent ELGs based on membrane filtration and established a pathway to opt into a subcategory that requires permanent cessation of coal combustion by December 31, 2028. After challenges to the 2020 ELG Rule by environmental groups, the EPA announced in 2021 that it would initiate a new rulemaking but stated that permitting authorities should continue implementation of the 2020 ELG Rule.

**Q. PLEASE DESCRIBE THE 2024 ELG RULE.**

A. On May 9, 2024, EPA finalized its "Supplemental Steam Electric Effluent Limitations Guidelines and Standards for the Electric Power Generating Point Source Category (the "2024 ELG Rule"). The 2024 ELG Rule adds additional requirements to the ELG rules described above and sets forth more stringent compliance pathways for the Company's scrubber wastewater and CRL. Most significantly, the 2024 ELG Rule established a ZLD requirement for scrubber wastewater and CRL from the Company's coal-fired generating units with compliance required by no later than December 31, 2029. The VIP and cessation of coal combustion subcategories remain unchanged from the 2020 ELG Rule. In the 2024 Rule, EPA also maintains the 2020 ELG Rule scrubber wastewater requirements and the December 31, 2025, deadline for phys-chem-bio treatment until the applicability dates of the new zero-discharge limitations are met.

The 2024 ELG Rule also adds a new subcategory option for electric generation units that are permanently ceasing coal combustion by 2034 and preserves the VIP compliance option. The 2024 ELG Rule also requires treatment of CRL at facilities that no longer burn coal.

**Q. HAS GEORGIA POWER UPDATED ITS ECS WITH REGARDS TO THE 2020 ELG RULE?**

A. Yes. Since the initial 2015 ELGs publication in November 2015, the numerous changes to the rule have made it necessary for the Company to maximize the flexibility of the environmental compliance strategy process to revise and optimize plans with each rule iteration and to continue studying evolving technologies, all while meeting compliance obligations currently in effect.

In light of the continuing increase to the Company's projected load forecast and the magnitude of capacity needs in 2028 and beyond, as discussed in the Direct Testimony of Witnesses Grubb, Hubbert, Looney, Robinson, and Valle, the Company is making a formal recommendation in this IRP to continue operations for Plant Bowen Units 1-2, as well as extending the operation of Plant Scherer Unit 3 and Plant Gaston Units 1-4 beyond the 2028 retirement dates approved in the 2022 IRP.

With the continued operation of Plant Bowen Units 1-2 beyond 2028, scrubber wastewater from those units will use the same treatment system currently under construction for Plant Bowen Units 3-4 to comply with the 2020 ELG Rule. For Plant Scherer Units 1-2, the Company considered plant-specific equipment and operational characteristics and selected a membrane-based technology system to meet the VIP compliance subcategory requirements by December 31, 2028. The site-specific water quality and quantity characteristics at Plant Scherer are a unique technical fit that allow the VIP pathway and membrane technology to be cost competitive. If the Commission approves Georgia Power's plan for the continued operation of Plant Scherer Unit 3 beyond 2028, the scrubber wastewater will be treated with the other units. In addition, based on current regulations, the compliance investments required at Plant Gaston Units 1-4 are expected to remain unchanged to continue operation beyond 2028.

**Q. HOW DOES THE 2024 ELG RULE CHANGE THE COMPANY'S COMPLIANCE PLANS AT PLANTS BOWEN AND SCHERER?**

A. Since the 2024 ELG Rule retained the VIP compliance option, no major change in compliance approach is needed for Plant Scherer for scrubber wastewater treatment. For Plant Bowen, the 2024 ELG Rule creates additional treatment needs. The Company has identified two potentially feasible alternatives:

(1) A membrane-evaporator-crystallizer system was established by EPA in the 2024 ELG Rule as the technology basis for the ZLD limit. The Company has included control assumptions and costs related to installation of a membrane-evaporator-crystallizer treatment system in the 2025 IRP as Plant Bowen's 2024 ELG Rule compliance option.

(2) The Company is also investigating and considering an alternative system that would exclude the membrane system from the first option. Should the alternative treatment system show technical viability and costs comparable to the membrane-evaporator-crystallizer system, the Company will pursue the alternative system.

The benefits of the Company's dual-path evaluation include: (i) the ability to perform further technical feasibility analysis, (ii) the ability to adjust to future regulatory changes, and (iii) the flexibility to install the best technology for the plant-specific scrubber wastewater volumes and characteristics.

In addition to scrubber wastewater, the 2024 ELG Rule requires ZLD of CRL at operational coal-fired facilities. Currently, the Company's plans for CRL treatment at Plants Bowen and Scherer are based on an evaporative process and estimated costs are at a prescreening level of certainty. For facilities that have previously retired coal-fired generation, the 2024 ELG Rule requires EPD to establish site-specific technology-based limits using best professional judgment. Accordingly, the 2024 ELG Rule's requirement for case-by-case technology-based effluent limitations established by the permitting authority will be subject to future permitting actions. Nevertheless, the Company is able to use current treatment technology assumptions and associated costs within the ECS for planning purposes.

**Q. IS THERE LEGAL UNCERTAINTY SURROUNDING THE 2024 ELG RULE?**

A. Yes. Like the 111 GHG Rules, the 2024 ELG Rule is currently in litigation before the Eighth Circuit Court of Appeals. Southern Company is a member of the Utility Water Act Group, one of the industry groups that is a petitioner on the challenge. Opening briefs were filed in November 2024, and on February 19, 2025, EPA requested that the court pause the litigation proceedings for 60 days. The rule remains in effect while the final outcome of the case is still pending. This means that the Company must continue its plan to achieve compliance with the 2024 ELG Rule and stay on track to complete systems to meet the compliance deadlines in the 2020 ELG Rule, while staying flexible for various legal outcomes.

**Q. HOW DOES THE COMPANY'S ELG COMPLIANCE STRATEGY ALLOW FOR FLEXIBILITY TO RESPOND TO FUTURE REGULATORY CHANGES?**

A. Georgia Power's ELG strategy benefits customers by providing a balanced plan to comply with existing requirements while maintaining flexibility to select the most appropriate unit-specific compliance options at certain sites. This plan best addresses the continuing uncertainty around the ultimate outcome of the ELG rule by moving forward on implementation of controls to ensure compliance by the required deadlines, while continuing to study wastewater treatment technology where there may be promising alternatives. This strategy provides the Company an ability to adapt to changing regulations while ensuring compliance and reliable operation moving forward.

### D. Legacy Rule

**Q. WHAT IS CCR?**

A. Coal Combustion Residuals, or CCR, are the byproducts produced from burning coal in coal-fired generation plants. As it relates to Georgia Power's operations, CCR includes fly ash, bottom ash, and gypsum. Fly ash and bottom ash are direct byproducts of the coal combustion process, whereas gypsum is the byproduct produced by the flue gas desulfurization process. CCR includes the fly ash, bottom ash, and gypsum produced from the Company's remaining operational coal units as well as the byproducts stored at Georgia Power's retired coal plants.

**Q. PLEASE DESCRIBE THE FEDERAL AND STATE REQUIREMENTS FOR CLOSURE OF ASH PONDS AND LANDFILLS.**

A. Georgia Power must comply with both the federal and state CCR rules at its ash ponds and CCR landfills. The federal CCR rule was finalized in 2015 (and amended numerous times thereafter) and established national minimum criteria for certain CCR landfills and ash ponds, including location restrictions, design and operating criteria, annual inspections, groundwater monitoring, corrective action, closure requirements and post-closure care, recordkeeping, notification, and internet posting requirements. The federal CCR rule mandates strict regulatory deadlines to complete closure of ash ponds.

The Georgia CCR rule finalized in 2016 adopted the federal CCR rule and additionally requires comprehensive permitting, oversight, and monitoring by EPD for all ash ponds and CCR landfills in the state. Both rules explicitly authorize closure-in-place and closure-by-removal as options for compliance, with each option subject to its own set of closure performance criteria. Neither rule dictates the use of either closure option in a particular instance. In fact, in establishing the federal CCR rule, EPA confirmed that both methods of closure—closure-in-place and closure-by-removal—are equally protective when the relevant performance criteria are properly implemented.

The federal and state CCR rules have both been amended numerous times over the past few years and Georgia Power expects they will continue to be reviewed and updated in the future.

**Q. HAVE NEW CCR RULES OR REGULATIONS BEEN FINALIZED SINCE THE 2022 IRP?**

A. Yes. On May 8, 2024, EPA issued the Legacy Rule. The Legacy Rule applies certain requirements from the existing CCR regulations as well as new compliance obligations to two categories of newly regulated CCR units: legacy CCR surface impoundments and CCR management units ("CCRMUs").

The Legacy Rule is expected to have limited impact on Georgia Power CCR units that meet the legacy CCR surface impoundments definition. Although previously exempt from federal regulation, Georgia Power's legacy CCR surface impoundments have all been regulated under Georgia EPD's CCR permitting program, previous state landfill permits, and/or state remediation programs. These units were or are being closed under the applicable state program. The finalization of the Legacy Rule, however, subjects these legacy units to duplicative requirements and oversight by both the state and federal agencies. While Georgia's comprehensive CCR, solid waste, and remediation rules have effectively regulated closure of CCR ash ponds and landfills in the state, the EPA's CCR Legacy Rule adds additional requirements.

First, the Legacy Rule defines a new type of CCR unit—CCR management units or CCRMUs. CCRMUs are areas of noncontainerized storage or management of CCR that are not part of an already-regulated CCR unit. The Legacy Rule requires facility evaluations at all current and former coal-fired power plant facilities to identify the potential existence of CCRMUs. This labor-intensive effort is due in two parts, within 21 months and 33 months of the final rule. Any CCRMUs that are identified through the facility evaluations are required to close and undertake groundwater monitoring and corrective action (where required) according to federal CCR rule requirements.

Second, the Legacy Rule definition for legacy CCR surface impoundments includes certain CCR units in Georgia that have been regulated by Georgia EPD. Although the applicability of the new Legacy Rule is not expected to significantly affect Georgia Power's closure plans, the Legacy Rule has the potential to introduce additional compliance timelines and impose additional monitoring requirements that may differ from current plans.

Third, the Legacy Rule codifies new definitions for key terms related to the performance standards for ash ponds that are closed in place. These new definitions for infiltration and liquids largely reflect EPA's new interpretations of these standards, first announced in January 2022, although uncertainty remains in the application of EPA's interpretations on a site-specific basis. In addition, the retroactive applicability of these new definitions has been legally challenged. While the impact of these definitional changes remains unclear pending legal outcomes, Georgia Power's closure-in-place units remain under the purview of the EPA-approved Georgia CCR permit program and include engineering controls designed to enhance groundwater protection.

**Q. DOES THE CCR LEGACY RULE DIRECT THE COMPANY TO CHANGE ITS CCR ASH POND CLOSURE STRATEGY?**

A. No. Georgia Power's ash pond closure strategy, including for legacy surface impoundments, is designed to comply with both the federal CCR Rule and the Georgia CCR Rule. The Company ceased placement of CCR in all ash ponds in 2019, and the CCR units are in various stages of closure under the oversight of Georgia EPD.

The ECS outlines Georgia Power's plans for complying with the Legacy Rule's administrative reporting requirements, website updates, and facility evaluations with associated reporting in 2026 and 2027, to identify the presence or absence of CCRMUs that could be subject to the CCR requirements.

**Q. IS THERE LEGAL UNCERTAINTY AROUND THE LEGACY RULE?**

A. Yes. The Legacy Rule was challenged by various parties and is in litigation before the U.S. Court of Appeals for the D.C. Circuit. Georgia Power's parent company, Southern Company, is a member of the Utility Solid Waste Activities Group, one of the industry groups that is a petitioner on the challenge. On January 31, 2025, petitioners filed opening briefs with the Court. Then, on February 13, 2025, the D.C. Circuit granted EPA's motion to hold the Legacy Rule litigation in abeyance for 120 days. Placing litigation in abeyance puts the litigation on pause, but it does not automatically stay the rule. Thus, at this time the Legacy Rule and its associated compliance dates are still in effect. Georgia Power will continue to monitor any new developments in the litigation and in the Legacy Rule and evaluate implications to the compliance strategy through the ECS process.

## IV. CCR COMPLIANCE STRATEGY

**Q. PLEASE DESCRIBE THE COMPANY'S CCR COMPLIANCE STRATEGY AS APPROVED IN THE 2022 IRP.**

A. The Company's CCR strategy was approved in the 2019 IRP and again in the 2022 IRP and remains unchanged since the 2022 IRP. The Company CCR compliance strategy covers 12 sites that include 29 ash ponds, 12 CCR landfills, and construction of a new permitted landfill that will support ash pond closures in the future.

**Q. WHAT IS THE COMPANY'S APPROACH TO IMPLEMENTING ITS ASH PONDS AND CCR LANDFILL CLOSURE STRATEGY?**

A. Georgia Power engaged third-party solid waste permitting experts to develop robust site-specific closure plans, including engineering designs and construction schedules to comply with the CCR rules. These plans comprehensively consider relevant factors in determining the appropriate closure designs for each unit, including volume, site complexity, and duration of the required activities, and are certified by independent, qualified professional engineers. For closure-in-place units, closure plans are developed following a detailed, site-specific engineering analysis that incorporates proven engineering methods designed to enhance groundwater protection, improve closure effectiveness, and minimize future maintenance. The Company's site-specific ash pond closure designs are included in the state CCR permits and are evaluated in detail by Georgia EPD. Regardless of the closure method selected for each CCR Unit, the Company will comply with applicable federal and state regulations as currently or subsequently enacted.

**Q. WHAT PROGRESS HAS THE COMPANY MADE WITH REGARD TO ITS CLOSURE STRATEGY?**

A. Georgia Power has made significant progress in implementing its approved closure strategy. The Company's semi-annual CCR ARO progress reports, filed with the

Commission in Docket No. 43083, provide additional details on the program's implementation status; however, key highlights include:

- As closure construction has advanced, Georgia Power has continued to prioritize safety through comprehensive planning, hazard recognition, engineering controls, training, a behavior-based safety program, and rigorous follow-through with learning events when risks are identified. Site-specific health and safety plans are developed and routinely assessed to minimize risks. Advancement of pre-closure or closure construction activities at 29 ash ponds includes permitting, landfill development, ash beneficiation infrastructure to support closure, dewatering, ash excavation, ash consolidation and placement, installation of closure cover systems, installation of engineering controls, and site restoration.

- In 2024, over 2,000 groundwater samples were collected by independent, third-party groundwater professionals with results included in 62 routine groundwater reports submitted to the Georgia EPD and posted to the Company's public website.

- In 2024, independent wastewater treatment contractors treated approximately 1.7 billion gallons of water and independent sampling contractors conducted 557 sampling events for the effluent and receiving streams. To date, over 6.14 billion gallons of water have been treated and over 3,325 sampling events have been conducted for the effluent and receiving streams. Water quality monitoring data is reported to the Georgia EPD and summarized on the Company's public website monthly.

- Beneficial use operations of harvested ash continued at Plant Mitchell and was initiated at Plant Bowen with over 400,000 tons of ash beneficiated in 2024. Construction of the beneficial use facility at Plant Branch is underway.

**Q. WHAT IS THE STATUS OF THE COMPANY'S PERMITTING PROCESS WITH THE GEORGIA EPD?**

A. To date, Georgia EPD has issued a total of 17 final permits—two closure-in-place permits, eight closure-by-removal permits, and seven landfill permits. Review of the remaining 14 permit applications continues with active engagement between the Company and the state agency. In addition, Georgia EPD has begun the five-year permit review process and has issued various minor modifications as projects have progressed for previously issued permits.

While Georgia EPD continues to maintain its EPA-approved state CCR permitting program, EPA involvement in Georgia CCR permits has increased in the last few years. In early 2024, EPA sent Georgia EPD a letter questioning the issuance of the final permit for Hammond AP-3, three months after the permit was finalized and more than two years after the draft permit was issued, and requested continued communication on all permit issuances. In April 2024, Georgia EPD responded to EPA stating that the permit was issued in accordance with the approved Georgia CCR Rule and meets the closure performance standards. Coordination between Georgia EPD and EPA on the Georgia CCR program is expected to continue for subsequent permitting actions.

With additional developments expected in 2025 related to Legacy Rule compliance, ongoing litigation, and other EPA actions, Georgia Power remains committed to working with Georgia EPD on the issuance of its remaining CCR permits, as required by the Georgia CCR Rule.

**Q. WHERE CAN INTERESTED PARTIES LEARN MORE ABOUT GEORGIA POWER'S CCR PROGRAM?**

A. Georgia Power maintains a comprehensive website detailing environmental compliance and project progress. The website includes details on the CCR permit application process with the Georgia EPD, providing extensive information on the

Company's closure plans and opportunities for engagement from stakeholders. The Company also publishes the results of water treatment, which are performed by independent third-party professionals and analyzed by accredited independent third-party laboratories, and publishes its semi-annual groundwater monitoring reports as submitted to EPD.

Additionally, in accordance with the 2019 IRP Order, Georgia Power continues to provide semi-annual progress reports to this Commission as well as annual updates with the annual ECS filing.

**Q. HAS GEORGIA POWER REVISED THE COST ESTIMATES FOR ITS CCR COMPLIANCE STRATEGY?**

A. Yes. Georgia Power consistently monitors and evaluates project assumptions, including, but not limited to, timing and schedule assumptions for permits and construction, project scope, post-closure activities, and estimated future escalation. The Company provides these updates in its CCR ARO semi-annual progress reports. As reflected in the CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 2, Georgia Power's current forecast applicable to retail customers over the next 60 years is approximately $8.0 billion, which includes $1.7 billion in project to date actual costs incurred through December 31, 2024.

## V. <u>BENEFICIAL USE</u>

**Q. WHAT IS BENEFICIAL USE?**

A. Beneficial use refers to the recycling or reuse of CCR into a marketable or useful product. Typically, CCR is reused as a key component in concrete products and wallboard. Ash adds strength and longevity when included in concrete specifications, while gypsum can replace mined gypsum for wallboard. Ongoing research continually seeks new beneficial uses for CCR, such as Georgia Power's involvement in research associated with extracting rare earth elements, which have applications in electronics manufacturing.

**Q. WHAT ARE THE POTENTIAL BENEFITS OF INCORPORATING BENEFICIAL USE INTO CERTAIN ASH POND CLOSURES?**

A. Benefits associated with the beneficial use of CCR can include increased ash sales, reduced closure costs, and reduced long-term liability. Reduced costs could take the form of reduced ash volumes moved during closure, a reduced closure footprint, reduced landfill space needed to support closure, and/or reduced post-closure care.

**Q. WHAT IS GEORGIA POWER'S APPROACH TO BENEFICIAL USE OF HARVESTED CCR IN ASH POND CLOSURE?**

A. Georgia Power uses a market-driven approach to optimize the potential of beneficial use in ash pond closure for the benefit of customers. This approach ensures that the benefits of harvested ash reuse is balanced with the infrastructure investment required and that the ash market remains able to absorb the amount of harvested ash produced from the Company's sites.

**Q. PLEASE DESCRIBE GEORGIA POWER'S EFFORTS TOWARDS THE BENEFICIAL USE OF CCR.**

A. The Company's CCR beneficial use efforts, as detailed in the ECS, center around three primary areas: (1) marketing of CCR from ongoing plant operations; (2) continued development of new research and technology for beneficial use of CCR; and (3) implementation of market-driven beneficial use projects at the Company's ash ponds and landfills.

**CCR Marketing**: Georgia Power has marketed, over a five-year average, over 85% of its CCR generated from plant operations for beneficial use. This results in a reduction in CCR, which helps minimize or offset costs related to CCR storage, landfill construction, and associated O&M.

**Research & Technology**: Georgia Power, in partnership with the Electric Power Research Institute ("EPRI") and other utilities, continues its efforts at the Ash Beneficial Use Center ("ABUC") located at Plant Bowen. The ABUC strives to develop additional beneficial uses and better technologies to process harvested ash for beneficial use. The Company continues to develop and explore research and beneficial use development opportunities as approved and further detailed in the 2019 and 2022 IRPs. Southern Company is also collaborating with Winner Water Services and Eco Material Technologies on a DOE-funded project to conduct a Front-End Engineering Design ("FEED") study for a commercial-scale rare earth elements extraction plant using coal ash as feedstock. The paper study will be based on Georgia Power's Plant Branch in Milledgeville, Georgia, as host site.

**Implementation of Beneficial Use Projects**: As part of site-specific ash pond closures, the Company currently has several beneficial use projects underway. At Plant Mitchell, Georgia Power anticipates that up to approximately two million tons of coal ash will be removed from Plant Mitchell's ash ponds to help create Portland cement. By the end of 2024, nearly half of this material has been removed and shipped off-site for beneficial use. This will further reduce the amount of ash required to be removed and relocated to an off-site landfill and ultimately result in the production of a valuable product.

At Plant Bowen, infrastructure construction for the new beneficial use facility is complete and commercial operations began in first quarter of 2024. Transportation of harvested ash from Plant Bowen's beneficial use facility for use in the ready-mix concrete market began in the first quarter 2024, with approximately nine million tons of ash anticipated to be harvested, processed, and removed from the site over the duration of the contract period.

Georgia Power also finalized an agreement for the beneficial use project at Plant Branch in May 2023, and investments are currently underway to build a processing facility with plans to excavate up to eight million tons of coal ash from on-site ash ponds for use in concrete. This will reduce the volume of ash to be landfilled on site.

## VI. CLIMATE & CARBON PRESSURES

**Q. WHAT ARE THE CARBON PRESSURES ON GEORGIA POWER'S GENERATING FLEET FROM CLIMATE AND ENVIRONMENTAL POLICY?**

A. In addition to the constraints imposed by new regulatory requirements such as the 111 GHG Rules, potential future climate regulation or legislation and evolving customer needs also present potential challenges and opportunities that are important to consider in the Company's overall planning process. In general, potential carbon cost or other climate-related pressures on generating units are highest for coal-fired generating units but also affect other fossil fuel-fired power plants.

**Q. HOW IS THE COMPANY INCORPORATING THIS INCREASED CARBON PRESSURE INTO ITS PLANNING PROCESSES?**

A. As described in the Direct Testimony of Witnesses Grubb, Hubbert, Looney, Robinson, and Valle, the Company's robust scenario planning process provides the best way to capture potential financial impacts and allow for long-term planning to mitigate risks to customers. Georgia Power included six scenarios in the IRP to reflect and evaluate carbon pressure: two scenarios are based on the 111 GHG Rules, three scenarios reflect varying levels of future carbon regulation and price pressure, and one scenario reflects the future adoption of an overall carbon emissions limit for the generating fleet. Considering the level of uncertainty in future climate policy, continued use of a range of carbon scenarios and costs in long-term planning best positions the Company to monitor and evaluate the outcome of executive, legislative, and regulatory actions and incorporate any new information into the planning processes as appropriate.

The Company continues to focus on the importance of planning strategically within the state regulatory framework to address the risks presented by carbon policy by ensuring a flexible generation fleet. Georgia Power recognizes that the feasibility of continued progress toward a low-carbon future is highly dependent on the continued use of natural gas and continued technology advancements. The Company's long-term planning approach considers these factors through a diverse resource portfolio leveraging low- and zero-carbon technologies, continued technological advancements, and constructive engagement with stakeholders to address the evolving energy needs and preferences of customers.

## VII. CONCLUSION

**Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN THE 2025 IRP AS IT RELATES TO THE ECS AND ENVIRONMENTAL COMPLIANCE?**

A. The Company seeks approval of the 2025 ECS. This includes the capital, O&M, and CCR ARO costs and associated measures taken to comply with federal and state environmental mandates, as set out in the ECS in Technical Appendix Volume 1 and the ECCR and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 2, as well as the authority to pursue the natural gas co-firing compliance pathway as the 111 GHG Rule strategy for Plant Bowen and Plant Scherer.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

**STATE OF GEORGIA**

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

| | | |
|---|---|---|
| **Georgia Power Company's 2025 Integrated Resource Plan** | ) ) | **Docket No. 56002** |
| **Georgia Power Company's 2025 Application for the Certification, Decertification, and Amended Demand-Side Management Plan** | ) ) ) ) | **Docket No. 56003** |

**DIRECT TESTIMONY OF**

**DR. ROSS BEPPLER, CARLEY GOFF, A. WILSON MALLARD,**

**AND ANDY PHILLIPS**

**FEBRUARY 28, 2025**

# DIRECT TESTIMONY OF
# DR. ROSS BEPPLER, CARLEY GOFF, A. WILSON MALLARD, AND ANDY PHILLIPS

## IN SUPPORT OF GEORGIA POWER COMPANY'S

## 2025 INTEGRATED RESOURCE PLAN DOCKET NO. 56002

## AND

## APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND SIDE MANAGEMENT PLAN DOCKET NO. 56003

### I. INTRODUCTION

**Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.**

A. My name is Dr. Ross Cannon Beppler. I am the Load Flexibility and Analysis Manager for Southern Company Services ("SCS"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Carley Jones McCloskey Goff. I am the Director of Demand Planning and Analysis for SCS. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Andrew Wilson Mallard. I am the Director of Renewable Development for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Richard Anthony ("Andy") Phillips. I am the Profitability and Economic Analysis Manager for SCS. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

**Q. DR. BEPPLER, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I began my academic studies at Clemson University, earning a Bachelor of Science in Electrical Engineering in 2014. Following this, I pursued a PhD in Energy and Environmental Policy from the Georgia Institute of Technology, which I completed in 2019. During my doctoral studies, I gained experience interning at the National Renewable Energy Laboratory, and at the Georgia Public Service Commission ("Commission"). From March 2018 to December 2019, I worked as a Quantitative Analyst with Demand Side Analytics, where I focused on data-driven insights on demand-side programs and technologies.

In 2019, I joined SCS as an analyst in the Planning and Regulatory Support organization. In 2022, I advanced to the role of Demand Analysis Manager. As of January 2024, I serve as the Load Flexibility and Analysis Manager, where I am responsible for design and evaluation of load flexibility programs and complimentary economic analysis.

**Q. DR. BEPPLER, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. No.

**Q. MS. GOFF, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I began my career in the energy sector after earning a Bachelor of Science in Finance from the University of Georgia in 2005. Shortly thereafter, I joined SCS as a Financial Analyst, where I worked from 2005 to 2007. In 2007, I transitioned to

Georgia Power, serving as a Profitability and Economic Analyst while pursuing my MBA from Emory University, which I completed in 2010.

Following my MBA, I continued at Georgia Power as a Financial Analyst from 2010 to 2012. I then advanced to the role of Metro East Region Financial Comptroller, a position I held until 2014. My career path then led me to become the Sales Manager for Outdoor Lighting from 2014 to 2015, followed by my role as Resource Management and Budget Manager from 2015 to 2018.

From 2018 to 2020, I served as the Assistant to the Executive Vice President, Chief Financial Officer, and Treasurer of Georgia Power. I then took on the role of Environmental Affairs Project Controls Manager from 2020 to 2024. Currently, I am the Director of Demand Planning and Analysis at Southern Company, a position I have held since April 2024.

**Q. MS. GOFF, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. No.

**Q. MR. MALLARD, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I have a Bachelor of Arts degree in Geography from the University of Georgia and an MBA degree from Mercer University. I began my career with Georgia Power in 1997 and have held various positions in Retail Sales and Service, Pricing and Rates, Energy Efficiency, Renewable Development, and Marketing. I served as the first manager of the Company’s Green Energy Program, and I helped create the Renewable Development organization in 2013. From 2013 until 2016, I was the Renewable Energy Planning Manager with primary responsibility for renewable energy strategy and program development for both Georgia Power’s renewable energy procurement plans and customer solar programs. I managed and oversaw the team responsible for all aspects of analysis, compliance, reporting, and communication related to the Company's renewable energy initiatives. Immediately prior to my current role, I served as Assistant to the Senior Vice President of Marketing for Georgia Power, where I provided oversight and assistance for all of Georgia Power's marketing, energy efficiency, energy services, sales, pricing, and planning activities.

Currently, I serve as the Director of Renewable Development for Georgia Power. In this role, I lead the development of renewable strategy and policy for Georgia Power Company, and am responsible for compliance in the administration of renewable programs and procurements.

**Q. MR. MALLARD, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. Yes. I testified in Docket No. 44160, Georgia Power Company's 2022 Integrated Resource Plan ("IRP"); Docket No. 43814, Georgia Power's Application for the Certification of the 2022/2023 Utility Scale Renewable Power Purchase Agreements ("PPAs"); Docket Nos. 4822, 16573, and 19279, the Commission's Review of Georgia Power's PURPA Avoided Cost Methodology; Docket No. 42625, Georgia Power's Application for the Certification of the 2020/2021 REDI Utility Scale PPAs; Docket No. 41596, Georgia Power's Application for the Certification of the 2018/2019 REDI Utility Scale PPAs; and Docket No. 41734, Georgia Power's Application for the Certification of the 2018/2019 REDI Utility Scale PPAs for the Commercial and Industrial ("C&I") Program.

**Q. MR. PHILLIPS, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated in 1996 from the Georgia Institute of Technology with a Bachelor of Science degree in Electrical Engineering. I also attended Emory University's Goizueta Business School, where I graduated with a Master of Business Administration ("MBA") in 2002. I began my career at Georgia Power in 1991 as part of the Co-Operative Education Program. Since 1997, I have held several roles with increasing responsibility in a variety of organizations including Distribution, Customer Service, Sales, and Planning and Pricing. I managed the Company's customer satisfaction programs from 2009 to 2012, served as a Key Accounts Team Manager from 2012 to 2017, and managed four teams within the Sales Organization as the Sales Support Manager from 2017 to 2018. In addition, I managed Georgia Power's electrical transportation programs while serving as the Electrification Manager from 2018 to 2019. I assumed my current role as the Profitability & Economic Analysis Manager in 2019, where I am responsible for leading the economic analysis in support of Georgia Power's energy efficiency programs.

**Q. MR. PHILLIPS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. Yes. I testified in Docket No. 44160, Georgia Power Company's 2022 IRP.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. Our testimony supports the Company's 2025 IRP and 2025 Application for the Certification, Decertification and Amended Demand Side Management Plan ("DSM Application") filed on January 31, 2025. We adopt the 2025 IRP and DSM Application as part of our testimony.

**Q. PLEASE SUMMARIZE THE TESTIMONY OF THE PANEL.**

A. The Company's Demand Side Management ("DSM") plan was developed in accordance with the Commission-approved DSM Program Planning Approach, per Commission orders, and in collaboration with the DSM Working Group ("DSMWG"). The Company developed four DSM cases in this case: the Proposed Case, the DSMWG Advocacy Case, the Supply-Side Case, and the Capacity and Affordability Case. The Company supports the adoption of the Proposed Case, which includes a DSM savings target of at least 0.75% of annual retail sales as required by the Commission's Order Adopting Stipulation in the Vogtle Prudency

Proceeding in Docket No. 29849 ("Vogtle Prudence Order"). Each of the other three cases were developed to evaluate the potential for varying levels of DSM investment and their impacts. The Company evaluated the cost effectiveness of these cases considering the impacts of the 111 Greenhouse Gas ("GHG") Rules by analyzing the economics within the moderate-gas, lower carbon pressure ("MG0") and moderate gas, zero-dollar carbon with 111 GHG Rules ("111-MG0") scenarios.

In support of its Proposed Case, the Company is seeking Commission approval for its DSM Action Plan, including (i) approval for a certificate of public convenience and necessity for one new residential DSM program, (ii) decertification of three previously certified DSM programs, (iii) amended certificates for four previously certified DSM programs, (iv) a waiver of the TRC requirement for four previously certified DSM programs, and (v) updated program economics for all other previously certified DSM programs. Approval of these DSM programs is projected to result in, on average, approximately 224 megawatts ("MW") of peak demand reduction and 741 gigawatt hours ("GWh") of energy reductions annually for 2026–2028. Although the economics of these programs are complicated, the Company continues to support offering DSM programs that minimize upward pressure on rates and maximize economic efficiency, especially as those programs contribute to high customer satisfaction.

Regarding DSM pilot programs and initiatives, the Company has launched seven residential pilot initiatives and six commercial pilots since the 2022 IRP. These programs inform future energy efficiency program design, and the Company seeks approval of a total of $3 million to continue these pilot studies as part of its DSM Action Plan. The Company is also requesting modifications to the additional sum methodology for these DSM programs, which will be simpler and likely more stable than the existing methodology.

Based on recent experience and customer feedback, the Company is proposing enhancements to its Utility Scale and Distributed Generation ("DG") renewable procurement processes. For both the Utility Scale and DG requests for proposals

("RFP"), the Company proposes new processes such as a submission refresh process to allow RFP participants the option to "buy down" the total cost of their submission, as well as offering extended RFP periods, which will maximize opportunities for project selection and procurement to meet customer renewable subscription needs. For Utility Scale RFPs specifically, the Company proposes adding flexible Required Commercial Operation Dates ("RCOD") and will continue to consider the use of operational tools and flexibility as solutions to support interconnection viability for projects. For DG RFPs, the Company proposes to make the energy procured through these RFPs available for subscription and seeks to include solar resources coupled with dispatchable storage as part of the procurement process. The Company also proposes to incorporate locational value to DG resources evaluated during Georgia Power's DG RFPs. With these enhancements, the Company is seeking to procure energy from up to 4,000 MW of new renewable resources by 2035, beginning with 1,000 MW from Utility Scale Resources through an RFP in 2026, and 100 MW from DG resources.

The Company is making several proposals related to its renewable and resiliency customer programs. For the Clean and Renewable Energy Subscription ("CARES") Utility Scale program, the Company proposes refinements to its Notice of Intent ("NOI") process, adding greater flexibility, and modifying its pricing methodology to reduce financial risks to non-participating customers. The Company also seeks to expand the CARES program to offer subscriptions to DG resources that are procured through Georgia Power's DG RFPs.

The Company seeks approval of the new Customer-Sited Solar Plus Storage Pilot Program, which will enhance options for customers interested in installing renewable resources at their premises. The Company also seeks to modify the existing Customer Connected Solar Program to add storage resources, increase the size of eligible facilities, and allow customers without billing history to participate.

The Distributed Energy Resource ("DER") Customer Pilot, DER Colocation Program, and DER Customer-Owned Program were all previously approved and are an important component of the Company's customer program portfolio. The Company is seeking to modify the DER Customer-Owned Program to allow contract terms up to 15 years. Otherwise, the Company is working closely with customers to move forward with projects in these programs and on its DER tariffs. In this 2025 IRP, the Company is proposing the Large Customer Owned Resiliency ("LCOR") Program, which is aimed at transmission-connected C&I customers. This program allows participants to retain ownership of their DER assets while providing Georgia Power with operational certainty that the assets will respond when called upon.

Finally, the Company is proposing a new Vehicle-to-Grid ("V2G") pilot program, which would enable electric buses at four school customer locations to transfer energy stored in their batteries back to the grid. By implementing this pilot program, the Company hopes to gain a better understanding of the costs associated with managing and administering this type of technology and the capabilities and value this technology provides to the Georgia Power electric system ("System").

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. The remainder of our testimony is organized as follows:

- Section II discusses the Company's Demand Side Strategy.
- Section III discusses enhancements to Georgia Power's Renewable Procurement Strategy.
- Section IV discusses the Company's Renewable and Resiliency Customer Programs, which includes a discussion about each of the following:
  - Modifications to the CARES program.
  - Customer Sited Renewable Offerings.
  - Customer Sited Resiliency Programs, including Georgia Power's DER Programs.
  - Vehicle to Everything Pilot.

## II. DEMAND SIDE STRATEGY

***Development of the DSM Portfolio***

**Q. HOW DOES GEORGIA POWER'S CURRENT DSM PORTFOLIO COMPARE TO ITS PROPOSED DSM PORTFOLIO?**

A. Georgia Power's current DSM portfolio consists of a combination of energy efficiency programs, a demand response program, pilots, and other DSM activities. The Company's proposed DSM portfolio in the 2025 IRP ("Proposed Case") continues to treat energy efficiency as a priority resource, aligning with Commission policy.

Consistent with the Vogtle Prudence Order, the Company's Proposed Case includes a performance savings target of 0.75% of annual retail sales. Further, in accordance with the Commission's Order Adopting Stipulation in the 2022 IRP (the "2022 IRP Order"), the Company also developed the "Supply-Side Case," modeling DSM programs alongside supply-side resources to identify combinations of supply-side and DSM resources to reliably meet load.

Additionally, the Proposed Case includes a new program offering, modifications to existing programs, and requests to decertify certain programs deemed no longer cost-effective. The Company projects that by 2028, its current DSM portfolio will represent approximately 1,400 MW, or approximately 8% of the Company's current peak demand. In this 2025 IRP, the Company is proposing a DSM plan that will result in an additional 741 GWh of energy reductions annually and 224 MW of peak demand savings for the years 2026–2028.

**Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE PROPOSED DSM PLAN.**

A. The proposed DSM plan was developed in accordance with the Commission-approved DSM Program Planning Approach, a nine-step process that ensures thorough evaluation and stakeholder engagement. The Company retained third-party consultants to assist with the planning, implementation, and evaluation of the DSM programs certified in the 2022 IRP Order. The Company completed and filed the Achievable Energy Efficiency Potential Assessment in January 2024 (with a subsequent Errata filing in November 2024) in the 2023 Demand Side Management Working Group docket, Docket No. 45051.

The Company continues to follow the Commission's economic screening policy outlined in the 2004 IRP Final Order in Docket No. 17687, which directs that the proposed DSM plans minimize upward pressure on rates and maximize economic efficiency. The Company evaluates the impact of its DSM programs on rates through the Rate Impact Measure ("RIM") test and determines the economic efficiency of its DSM programs using the Total Resource Cost ("TRC") test. As demonstrated through the Company's planning processes, DSM is treated as a priority resource and reduces the Company's energy and demand forecast before supply-side alternatives are considered.

Georgia Power collaborated with the DSMWG to develop, discuss, and refine DSM program concepts for the 2025 IRP. The DSMWG provided feedback on program design, economic modeling, and customer outreach strategies. The Company engaged with the larger DSMWG eight times since 2022 to discuss proposed program modifications and new initiatives, as well as a subset of the DSMWG to specifically work through program ideation. This process ensured broad stakeholder input in the DSM program development process.

Georgia Power's DSM plan also incorporates findings from recent program evaluations, updates to measure impacts, and economic analyses using the TRC and RIM tests. The DSM Program plans have also been informed by developments since the 2023 IRP Update, including the issuance of the Vogtle Prudence Order and an increase in the marginal cost of generating energy. The DSM Program plans included in the DSM Application represent a well-balanced portfolio of residential and commercial DSM programs that are structured to help customers reduce and better manage their energy usage.

**Q. DOES THE PLANNING PROCESS THAT THE COMPANY USED TO DEVELOP THE PROGRAMS SATISFY THE COMMISSION'S DSM EVALUATION RULE?**

A. Yes. Georgia Power's planning process adheres to the Commission's DSM evaluation rule. The process included stakeholder engagement, adherence to the DSM Program Planning Approach, and economic screening that aligns with Commission standards. The DSM portfolio was developed through a rigorous assessment of market potential, cost-effectiveness testing, and alignment with regulatory expectations. Completion of the DSM Program Planning Approach, including the filing of the Achievable Energy Efficiency Potentials Assessment, satisfies the requirements of the Commission's DSM Evaluation Rule.

**Q. HOW WERE THE PROGRAMS CERTIFIED BY THE COMMISSION IN THE 2022 DSM APPLICATION AND THE 2023 IRP UPDATE EVALUATED?**

A. Georgia Power engaged third-party consultants to assess program performance for both the 2022 DSM programs and those modified in the 2023 IRP Update. Evaluations focused on energy savings, cost-effectiveness, and market impact. The findings informed the program adjustments proposed in the 2025 IRP.

**Q. DID THE COMPANY CONSIDER THE POTENTIAL IMPACT OF THE SECTION 111 GREEN HOUSE GAS RULES WITH RESPECT TO ITS DSM ECONOMIC ANALYSIS?**

A. Yes, the Company's DSM program economic analysis includes an evaluation of the MG0 and 111-MG0 scenarios.

***Development of the DSM Cases***

**Q. HOW DID THE VOGTLE PRUDENCE ORDER INFLUENCE THE DEVELOPMENT OF THE DSM PROPOSED CASE IN THIS IRP?**

A. In developing the Company's Proposed Case, Georgia Power established the energy savings target in compliance with the Vogtle Prudence Order, which required Georgia Power to propose a DSM performance savings target of at least 0.75% of annual retail sales. Consistent with the composition of the Company's current DSM portfolio, these savings were calculated to come from the residential and commercial customer classes only.

**Q. DOES THE COMPANY SUPPORT THE PROPOSED CASE?**

A. Yes. As explained previously, the Proposed Case provides a comprehensive portfolio of energy efficiency and demand response programs, pilots, and other DSM initiatives prepared through the Commission's DSM Program Planning Approach, consistent the Commission's policy of minimizing upward pressure on rates and maximizing economic efficiency, in compliance with prior Commission orders.

**Q. WHAT IS THE CAPACITY AND AFFORDABILITY CASE?**

A. The Capacity and Affordability case is a sensitivity developed for informational purposes. Although the Proposed Case provides substantial energy savings, those savings come at an increased cost to customers, the majority of whom do not participate or receive savings from the DSM portfolio. The Company continues to see value in DSM as a priority resource and presents the Capacity and Affordability Case so the Commission can consider how to best balance energy savings and customer rate impacts.

**Q. PLEASE DESCRIBE EACH OF THE DSM CASES PRESENTED IN THIS IRP.**

A. Georgia Power analyzed the following four DSM cases to evaluate the potential for varying levels of DSM investment and their associated impacts, including cost-effectiveness:

- **Proposed Case**: The Proposed Case adopts the 0.75% of annual retail sales savings target established by the Vogtle Prudence Order. The demand response and energy efficiency programs included in the Proposed Case are projected to achieve approximately -$16 to $3 million in annual net TRC benefits while putting upward pressure on rates of approximately $630 to $746 million annually under the MG0 economic scenario. For the 111-MG0 economic scenario, the Proposed Case is projected to achieve approximately -$3 to $24 million in annual net TRC benefits while putting upward pressure on rates of approximately $609 to $733 million annually over years 2026, 2027, and 2028.

- **DSMWG Advocacy Case**: Based on requests made by certain members of the DSMWG, the DSMWG Advocacy Case was developed as a sensitivity to the Proposed Case. The DSMWG Advocacy Case is similar to the Proposed Case but includes an industrial program. The implementation of the DSMWG Advocacy Case would achieve approximately -$12 to $8 million in annual net TRC benefits while putting upward pressure on rates of approximately $641 to $761 million annually under the MG0 economic scenario and achieve approximately $1 to $29 million in annual net TRC benefits while putting upward pressure on rates of approximately $620 to $748 million annually under the 111-MG0 economic scenario for years 2026–2028. The Company does not support the inclusion of an industrial DSM program because the Company's experience has shown that industrial customers generally adopt DSM and energy efficiency measures on their own, without the need for customer-funded incentive programs. As such, the Company does not recommend this case and presents the results of the DSMWG Advocacy Case for informational purposes only.

- **Supply-Side Case**: As agreed to in the 2022 IRP Stipulation and approved by the Commission, the Supply-Side Case modeled DSM programs alongside supply-side resources to identify the most cost-effective combination of supply-side resources and DSM programs. The Supply-Side Case replaces the previously used Aggressive Case in the DSM Program Planning Process for the 2025 IRP. The supply side modeling system, Aurora, evaluates resources on a relative net present value basis, so traditional DSM cost-effectiveness tests are not applicable. Under the 111-MG0 economic scenario, the Supply-Side Case yielded the highest annual costs in the years 2026–2028 of any of the four DSM cases. In addition, the MG0 scenario selected no income-qualified programs for the years 2026–2028.The Company does not recommend adoption of the Supply-Side Case.

- **Capacity and Affordability Case**: The Capacity and Affordability Case was developed in light of the significant upward pressure on rates resulting from the Proposed Case, and attempts to substantially mitigate the upward pressure on rates associated with the Proposed Case. The Capacity and Affordability Case strikes a balance between customer affordability concerns, capacity constraints, and the value of energy efficiency programs. This case achieves approximately $80 to $92 million annually in net TRC benefits from 2026–2028 while putting upward pressure on rates of approximately $162 to $211 million annually under the MG0 economic scenario. Under the 111-MG0 scenario, the Capacity and Affordability Case achieves approximately $84 to $100 million annually in net TRC benefits while putting upward pressure on rates of approximately $154 to $206 million annually from 2026–2028.

**Q. WHAT SPECIFIC APPROVAL IS THE COMPANY SEEKING IN THIS CASE?**

A. Georgia Power seeks Commission approval of the Company's DSM Action Plan for the Proposed Case, which includes (i) approval for a certificate of public convenience and necessity for one new residential DSM program, (ii) decertification of three previously certified DSM programs, (iii) amended certificates for four previously certified DSM programs, (iv) a waiver of the TRC requirement for four previously certified DSM programs, and (v) updated program economics for all other previously certified DSM programs. Further, the Company requests modifications to the additional sum methodology and approval to continue other DSM activities like the Learning Power Education and Energy Efficiency Awareness initiatives and pilot studies.

***The DSM Programs***

**Q. PLEASE DESCRIBE THE NEW RESIDENTIAL PRODUCTS PROGRAM THAT THE COMPANY SEEKS TO CERTIFY.**

A. The Residential Products Program is designed to incentivize customers to adopt high-efficiency appliances, electronics, and home energy upgrades by providing rebates for ENERGY STAR-certified HVAC systems, smart thermostats, water heating, and other technologies. The program integrates customer education initiatives to promote long-term efficiency improvements. A key aspect of the Products program is for the customer to achieve energy and demand savings through the installation of energy-efficient measures. Participating customers have multiple channels to access discounts, rebates, and other incentives to purchase energy efficient products that bring additional energy and demand savings to their home.

**Q. PLEASE EXPLAIN WHY THE COMPANY SEEKS TO DECERTIFY THE RESIDENTIAL REFRIGERATOR RECYCLING PLUS PROGRAM.**

A. The Company seeks to decertify the Residential Refrigerator Recycling Plus Program due to several key factors limiting its effectiveness and efficiency. As newer appliances are and have been designed to be more energy-efficient and have entered the marketplace over the last three decades, the potential energy savings from recycling such appliances have become significantly lower than in years past. Additionally, the costs associated with recycling appliances like refrigerators and freezers have increased. This imbalance between decreasing savings and rising costs makes the program less cost-effective. There are also fewer appliance recycling vendors available in the market, complicating the implementation and operation of the recycling program as designed and further reducing its feasibility.

Given these considerations, continuing the Residential Refrigerator Recycling Plus Program is no longer practical. The Company aims to reallocate these resources to other programs that can deliver greater energy savings and benefits to our customers.

**Q. PLEASE EXPLAIN WHY THE COMPANY SEEKS TO DECERTIFY THE RESIDENTIAL SPECIALTY LIGHTING PROGRAM.**

A. The Company proposes to decertify the Residential Specialty Lighting Program due to significant changes in the market and regulatory landscape. Over the last several years, there has been a substantial shift towards the widespread availability of residential energy-efficient lighting options, largely driven by market transformation and enhanced federal regulations. Together, these have made energy-efficient lighting products more accessible to consumers.

As a result, the need for incentivizing such lighting measures through designated programs has diminished. The energy savings that were once achieved through the program are no longer as significant because consumers can now easily obtain these energy-efficient lighting without additional incentives. Consequently, continuing to support this program is not cost-effective for the Company. By reallocating resources from this program, the Company can focus on other initiatives that offer greater energy savings and benefits to customers.

**Q. PLEASE EXPLAIN WHY THE COMPANY SEEKS TO DECERTIFY THE COMMERCIAL BEHAVIORAL PROGRAM.**

A. The Company requests the decertification of the Commercial Behavioral Program based on findings from a third-party evaluation that the program was not cost-effective. Per the 2022 IRP Order based on program evaluation findings, the Company suspended the implementation of the Commercial Behavioral Program in 2025, pending decertification.

**Q. PLEASE DESCRIBE WHY THE COMPANY SEEKS A WAIVER OF COMMISSION RULE 515-3-4-.04(4)(A)(3) FOR ONE COMMERCIAL AND THREE RESIDENTIAL PROGRAMS.**

A. Commission Rule 515-3-4-.04(4)(a)(3) requires that demand-side programs pass the TRC test. The Commercial Custom Program, Residential Home Energy Improvement Program, Residential Energy Assistance for Savings and Efficiency Program, and the Residential Hopeworks Program have demonstrated high customer satisfaction and market potential for energy savings. However, each of these four programs do not reflect positive TRC results for the 2025 IRP cycle due to the costs required to achieve the large energy savings goal represented in the Proposed Case. Therefore, to continue offering these programs to customers as part of the Company's proposed DSM plan, Georgia Power requests a waiver of Commission Rule 515-3-4-.04(4)(a)(3) for these four programs.

**Q. FOR WHICH PROGRAMS IS THE COMPANY REQUESTING AMENDMENTS TO THE PROGRAM CERTIFICATES?**

A. The Company seeks to amend the certificate for each of the four programs for which the Company is seeking a waiver of the TRC requirement. In addition, the Company seeks to amend the program certificates for the Residential Behavioral Program, the Residential Demand Response Program, the Commercial Prescriptive Program, and the Small Commercial Direct Install Program.

***Evaluation and Impact of DSM Programs***

**Q. WHAT ARE THE EXPECTED IMPACTS OF THE COMPANY'S PORTFOLIO OF PROPOSED DSM PROGRAMS ON PEAK DEMAND AND ENERGY USAGE?**

A. The Company projects that its proposed energy efficiency programs will result, on average, in approximately 224 MW of peak demand reduction and 741 GWh of energy reductions annually for 2026–2028, based on the planned implementation levels.

**Q. HOW WILL GEORGIA POWER MEASURE THE SUCCESS OF THESE DSM PROGRAMS?**

A. The Company will track program performance and progress toward achieving established goals on an ongoing basis. Through a RFP solicitation, Georgia Power will contract with independent, third-party evaluators to conduct comprehensive program evaluations at regular intervals (initially planned for three-year intervals). The evaluations will include market, process, and impact evaluations to review the program's operations, evaluate the program's impact on the local market, and verify the energy and demand savings produced by the program. The Company will begin implementing evaluation results and applying deemed savings to the new program cycle beginning in January 2029 to be consistent with the Company's three-year IRP and DSM planning cycles.

**Q. WHAT STEPS DID THE COMPANY TAKE TO BALANCE THE INCREASED DSM SAVINGS TARGETS WITH COST-EFFECTIVENESS CONSIDERATIONS?**

A. The Company performed TRC and RIM analyses to evaluate the cost-effectiveness of various program designs. While some programs remained cost-effective, others required modifications, and the Company is seeking decertification of a few programs due to declining economic viability. The Company designed channels within programs and grouped DSM offerings where possible to enable flexibility and options for obtaining energy savings with minimal program costs.

**Q. HOW HAS THE INCREASED DSM SAVINGS TARGET AFFECTED THE TRC AND RIM TEST RESULTS FOR THE PROPOSED DSM PROGRAMS?**

A. The increased savings target has led to declining TRC test results and negative RIM test results for several programs. Higher energy efficiency goals require additional resources, including higher incentives, which increase program costs and impact customer rates.

**Q. HOW DID THE COMPANY CONDUCT THE ECONOMIC SCREENING FOR THE DSM PROGRAMS IN THE 2025 IRP?**

A. The Company continues to follow the Commission's economic screening policy outlined in the 2004 IRP Order in Docket No. 17687. This policy requires the Company to offer a DSM plan that minimizes upward pressure on rates and maximizes economic efficiency. The Company screened each of the four DSM planning cases against the MG0 and 111-MG0 scenarios.

**Q. HOW DOES THE COST-EFFECTIVENESS OF THE PROPOSED CASE COMPARE TO THE PROPOSED CASE APPROVED IN THE 2022 IRP?**

A. Relative to the 2022 IRP economic test results, the TRC test results declined, and RIM test results remain negative for the Company's proposed case. For comparison, in the 2022 IRP, the Company's proposed case achieved approximately $90 to $112 million in net TRC benefits, while putting upward pressure on rates of approximately $325 to $334 million annually for years 2023–2025.

**Q. WHAT IS THE PRIMARY CAUSE OF DECLINING DSM PROGRAM ECONOMICS?**

A. Even though avoided energy costs have increased since the 2022 IRP, which has a positive impact on energy efficiency economics, both TRC and RIM test results have declined primarily due to the substantial resources and higher incentives needed to achieve high energy savings in the Proposed Case. This trend in declining economics continues to raise concerns for the Company as it strives to balance the economic benefits that DSM programs provide to participating customers with the rate impacts to all residential and commercial customers, whether they participate in the programs or not. The Company plans to monitor program costs and economics through 2028 and will be prepared to modify programs if significant upward pressure on rates continues.

**Q. WHY IS THE COMPANY SEEKING APPROVAL TO CONTINUE DSM PROGRAMS IF THEY ARE LESS ECONOMIC THAN THEY WERE THREE YEARS AGO IN THE 2022 IRP?**

A. As stated previously, the Company continues to support offering a DSM plan that minimizes upward pressure on rates and maximizes economic efficiency, consistent with existing Commission policy. The Company used this same philosophy in analyzing the slate of programs considered for certification in the 2022 DSM

Application and the 2023 IRP Update. As the net benefits from these programs decline and the cost in terms of rate impact increases, it becomes more challenging to maintain that balance.

Nevertheless, in light of DSM program benefits, the Company supports the continuation of DSM as outlined in its DSM Action Plan. These programs are designed to enhance energy efficiency and provide customers with more control over their energy usage. In addition, these DSM programs contribute to high customer satisfaction, and customers expect that the Company will continue making these DSM programs available to them.

Building on the momentum from the 2022 IRP, Georgia Power continues to focus on offering additional DSM options for income-qualified customers. The Company is including additional measures, as well as measures for manufactured homes, in its Energy Assistance for Savings and Efficiency ("EASE") and HopeWorks programs. The Company has also increased the energy savings carve out for income-qualified participants in the Residential Behavioral Program to 33%. Further, the Company has designed EASE to include moderate income customers, who can also participate in the program and receive up to $5,000 of free energy efficiency improvements. Income level eligibility for these programs will be developed during program implementation based on market best practices, and will enable coordination with other energy efficiency programs, philanthropic groups, and governmental programs.

***<u>DSM Pilot Programs & Awareness Initiatives</u>***

**Q. WHAT PILOT PROGRAMS WERE CONDUCTED SINCE THE 2022 IRP?**

A. Since the 2022 IRP, Georgia Power has launched seven residential pilot initiatives:

- Income Qualified Portal;
- Manufactured Homes;
- Phase Change Insulation;

- EV Managed Charging;
- All-in-One Heat Pump Washer Dryer;
- Sense Energy Efficiency; and
- the Equity Insights and Engagement Research pilot.

Additionally, the Company launched six commercial pilots:

- Energy Monitoring and Intelligence;
- Digital Twin Energy Management;
- IoT Building Management;
- Aeroseal Duct Insulation;
- Small Commercial Induction Cooking; and
- Small Commercial Direct Install Equity and Engagement Research pilot.

These pilots inform future energy efficiency program design with measurement and verification of emerging technology and customer satisfaction. They directly influence innovative DSM pilot and program delivery mechanisms. Some of these pilots continue to focus on providing historically under-represented customers and small and medium business customers access and participate in energy efficiency programs. The Company seeks Commission approval to continue pursuing DSM pilot studies as part of its DSM Action plan.

**Q. WHAT IS THE COMPANY'S REQUESTED BUDGET FOR DSM PILOT STUDIES?**

A. The Company seeks Commission approval for $1.5 million for residential and $1.5 million for commercial pilot studies annually, which is equal to the amounts approved in the 2019 and 2022 IRPs.

**Q. IS THE COMPANY PROPOSING TO CONTINUE ITS ENERGY EFFICIENCY AWARENESS INITIATIVES?**

A. Yes. The Company proposes to continue offering its energy efficiency awareness initiatives to customers, which promote the benefits of energy efficiency and educate customers about ways to save energy. Based on the continued success of this program and the high customer satisfaction derived from these initiatives, the Company has requested continued funding for these activities, consistent with what the Commission approved in the 2022 IRP.

**Q. IS GEORGIA POWER PROPOSING TO CONTINUE ITS LEARNING POWER INITIATIVE?**

A. Yes. The curriculum of the Learning Power Initiative promotes a grassroots understanding of energy and energy efficiency, with lessons for grades pre-K through 12. The program is highly interactive and hands-on, with lessons taught by skilled Georgia Power Education Coordinators. Education Coordinators are assigned a geographic region of the state, with an equitable distribution of students and schools. Between 2011 and December 31, 2024, the Company delivered 42,124 Learning Power Education Initiative programs to over 1.3 million students in Georgia. Based on the continued success of this program and the positive feedback from educators, the Company has requested continued funding for these activities, consistent with what the Commission approved in the 2022 IRP.

***<u>Regulatory Treatment of DSM Program Costs and Additional Sum</u>***

**Q. PLEASE DESCRIBE THE COMPANY'S REQUEST REGARDING DSM COST APPROVAL.**

A. The Company is requesting Commission approval of the costs for all approved and certified DSM programs, pilots, and other DSM activities. In addition, the Company requests the continued collection of an additional sum. The budgets and costs for the Company's DSM programs are set forth in Appendix C to the DSM

Application, and the additional sum amounts are set forth in Appendix F to the DSM Application.

**Q. PLEASE DESCRIBE GEORGIA POWER'S ADDITIONAL SUM REQUEST FOR THE PROPOSED CASE.**

A. As stated in the DSM Application, the Company requests an additional sum equal to four cents for every kilowatt hour ("kWh") saved using verified net energy savings values applied to all certified DSM programs in the residential and commercial DSM portfolios. Any authorized additional sum will be specific to the corresponding customer class and will be collected through the residential and commercial DSM tariffs. The additional sum included in the DSM tariffs will apply the four cents per kWh saved to the total net energy savings estimated in the Proposed Case.

**Q. WHY DOES THE COMPANY WANT TO CHANGE THE ADDITIONAL SUM METHODOLOGY?**

A. The proposed additional sum methodology is simpler than the existing methodology and likely to be more stable. The proposed change in methodology also better aligns the additional sum with the energy savings achieved from the customer classes eligible to participate in the Company's residential and commercial DSM programs. Further, the proposed methodology will value energy savings from every program equally as opposed to the current methodology, where Georgia Power receives little to no additional sum from residential DSM programs that deliver kWh savings. The Company believes the proposed approach will also help streamline the reporting process and provide additional clarity around the annual DSM tariff true-up process.

**Q. IF THE COMPANY IS USING VERIFIED NET ENERGY SAVINGS IN ITS CALCULATION OF THE ADDITIONAL SUM, ARE MARKET EFFECTS ALREADY TAKEN INTO ACCOUNT?**

A. Yes. Market effects such as free-ridership and spillover are recognized in the industry as important data points for evaluating DSM programs and deciding whether to modify or continue DSM programs. Market effects are useful for program evaluations and modifications, as well as future program design and system planning.

**Q. HOW DOES THE COMPANY PROPOSE TO COLLECT DSM PROGRAM COSTS AND THE PROPOSED ADDITIONAL SUM?**

A. Georgia Power proposes to collect the costs of approved and certified DSM programs and activities, as well as the additional sum amount for certified DSM programs, through the existing residential and commercial DSM tariffs. These tariffs would be filed as part of the Company's next base rate case and would be implemented with any approved change in rates thereafter.

**Q. WILL THE DSM TARIFFS BE TRUED UP?**

A. Yes. Consistent with current practice, the DSM tariffs will initially be based on projected program costs and participation levels, and projected additional sum values approved in the 2025 IRP and DSM Application. Subsequently, the DSM tariffs should be trued-up annually based on actual program costs and participation levels, and actual revenues collected using the true-up methodology agreed to by the Company and Commission Staff.

## III. RENEWABLE PROCUREMENT AND PROGRAM STRATEGY

***Renewable Procurement Strategy***

**Q. PLEASE DESCRIBE GEORGIA POWER'S NEED TO ENHANCE ITS RENEWABLE PROCUREMENT PROCESSES.**

A. Georgia Power takes pride in the measured and disciplined approach it has taken over the last decade to responsibly integrate additional renewable resources onto its System for the benefit of all customers. Planning models indicate the continued addition of economic renewable resources offers value to all customers across multiple scenarios, and the actions of the Commission, the market, and the Company have delivered economic renewable resources to the System. Additionally, as the number of customers with sustainability goals increases, the Company has adapted its renewable procurement strategies to evolve with changing customer demand and the sustained interest in renewable subscription programs.

Through market interaction and recent RFP experience, the Company has identified several challenges and opportunities that necessitate modifications to further enhance its procurement processes. For example, changing interconnection processes and requirements, impacts from regulatory uncertainty and policy changes (tariffs, tax credits, grants, etc.), increasing scrutiny on land use, supply chain issues, and a difference in the timelines of proposed renewable procurements and transmission system improvements have all limited the Company's ability to meet its renewable RFP targets.

Further, the Company received feedback from market participants indicating a need for additional flexibility to navigate changing regulatory policies and supply chain dynamics, including modifications to RCODs. These market conditions, combined with customer desires for subscriptions to incremental renewable resources, drive the need for more flexibility in the Company's RFP process, including consideration of customer identified resources.

As a result of these challenges and the feedback received, Georgia Power's RFPs must become more flexible and adaptable to capture the value that renewable resources can offer to customers. To that end, the Company's proposed enhancements apply these lessons learned and are aimed at improving the efficiency and success of its renewable procurements.

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ENHANCEMENTS TO THE RENEWABLE PROCUREMENT PROCESS.**

A. Georgia Power proposes to modify its renewable procurement strategy by introducing several enhancements to its Utility Scale and DG RFPs. For both the Utility Scale and DG RFPs, the Company will continue using a best-cost evaluation methodology but will also introduce new processes such as (1) a submission refresh option to "buy down" project cost and (2) an extended RFP period designed to maximize opportunities for project selection and procurement to meet customer needs.

In the Utility Scale RFP process, the Company proposes adding flexible RCODs, allowing projects to have a wider range of acceptable in-service dates and enabling RFP participants and the Company to navigate market challenges such as supply chain disruptions and changing policy landscapes. Additionally, the Company will continue to consider the use of Transmission System operational tools and flexibility that support interconnection viability for projects and portfolios of projects.

For DG RFPs, the Company proposes to make the energy procured available for subscription and also seeks to include solar resources coupled with dispatchable storage to deliver additional capacity value to benefit all customers. Finally, the Company proposes to enhance its locational guidance to customers by updating the RCB framework used in the DG evaluation process to assign value to projects based on their geographic location. By incorporating locational value into the DG RFP evaluation, the Company aims to incentivize strategic siting decisions of flexible, dispatchable resources to better support the System when and where it is needed most.

***Utility Scale RFPs***

**Q. WILL THE COMPANY CONTINUE TO USE THE BEST COST METHODOLOGY IN ITS UTILITY SCALE RFP EVALUATIONS?**

A. Yes. As approved in the 2022 IRP Order, the Company's ongoing RFPs are evaluated using the best-cost methodology, which enables procurement of renewable resources at the best cost for Georgia Power customers. This approach to the evaluation process considers all benefits delivered by proposals in relation to multiple planning scenarios. This process provides more flexibility for the Company, in conjunction with Staff and the Independent Evaluator, supporting a selection process that is more likely to meet RFP procurement targets.

**Q. PLEASE DESCRIBE THE MULTI-PHASE RFP PROCESS PROPOSED BY THE COMPANY FOR ITS UTILITY SCALE PROCUREMENTS.**

A. The Company proposes enhancing its utility scale procurements by implementing a two-phase process. In Phase I, the Company would implement a traditional RFP to procure resources. Phase I would also include an added submission refresh process to allow projects to "buy down" their project costs to provide the ability for more projects to be procured as needed.

Phase II is an optional phase in which the RFP remains active for an extended period and offers additional customer subscription opportunities. Phase II would only be available, if necessary, to address customer needs that may remain after the conclusion of Phase I.

**Q. PLEASE EXPLAIN THE COMPANY'S PHASE I PROPOSAL.**

A. As noted above, Phase I consists of a traditional competitive solicitation conducted in accordance with the Commission's RFP rules consistent with past practice. Each proposal submitted into an RFP is evaluated and ranked based on the levelized total net benefits to Georgia Power's customers on a dollar per MW hour ($/MWh) basis.[1] RFP submissions are then further evaluated by the Company and an Independent Evaluator for transmission and environmental impacts. Competitive submissions that meet the Company's best cost threshold are deemed to provide net benefits for customers are moved to a Short List. Short List proposals comprise the winning portfolio of resources that proceed to contract execution.

If customer subscription needs remain after the Company identifies the Short List in the traditional portion of the Phase I RFP, the Company proposes to then return to the fully evaluated list of proposals not selected for the Short List. These submissions will then be offered the opportunity to execute a contract or otherwise move forward in the process if the participant can refresh the submission price such that the net benefit of the project is equal to the average total net benefit of the Short List portfolio of resources originally selected. This submission price refresh process will be designed in compliance with Commission RFP rules to ensure that any additional projects selected through this process meet the Commission's certification requirements.

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[1] The total net benefit of a proposal is calculated by comparing the costs customers will pay if the proposal advances to the projected costs customers would otherwise incur if the proposal were not advanced ("Total Net Benefit").

**Q. PLEASE EXPLAIN THE COMPANY'S PHASE II PROPOSAL.**

A. The Company proposes to add a second phase to the Utility Scale RFP process, which extends the RFP and allows new projects to be submitted at or below a price target that results in a Total Net Benefit that is greater than or equal to the average Total Net Benefit of the winning portfolio of resources from the Phase I procurement. As part of this Phase II process, customers interested in subscribing to the Company's CARES program can work with developers to self-identify resources and submit additional proposals to meet additional customer subscription demand not otherwise satisfied by Phase I of the proposed RFP process ("Customer Identified Resources" or "CIRs").

Project developers and potential subscribers can collaborate to submit proposals to meet a price target that ensures new projects will deliver a Net Benefit greater than or equal to the original portfolio's Total Net Benefits. Additionally, RFP participants can submit new proposals in this extended RFP process independently, offering potential subscribers the opportunity to subscribe to additional projects at prices that ensure no costs are shifted to non-participating customers. Proposals submitted into Phase II will undergo a full evaluation, including a transmission analysis, in order to provide final pricing that ensures such projects deliver value to all customers.

Phase II would only be made available if there are unmet CARES Utility Scale customer subscription needs. Thus, this additional phase provides additional customer subscription opportunities, if necessary, while simultaneously securing additional renewable resources in a manner that preserves benefits and protects all customers.

**Q. WHAT DOES IT MEAN THAT THE COMPANY WILL OFFER FLEXIBLE CODS?**

A. The Company will incorporate a range of RCODs sought in its RFPs rather than limiting resources to only one, specific COD window. Based on the outcomes of recent RFPs, Georgia Power has proposed to use a range of COD years to incorporate additional flexibility for participants and for the Company in its competitive solicitations.

***<u>Distributed Generation RFPs</u>***

**Q. WHICH ENHANCEMENTS TO THE UTILITY SCALE PROCESS WILL ALSO BE APPLIED TO THE DG PROCUREMENT PROCESS?**

A. The Company proposes to continue utilizing the best cost-methodology in its DG procurement process. Additionally, the Company proposes implementing the same two-phase RFP approach outlined above to the DG procurement process, including the Phase I plus the submission refresh process and the additional Phase II CIR process. As with the utility scale RFP process, the submission refresh option enhancement to buy down project costs in Phase I and the Phase II CIR process would be available only if there continues to be an unmet customer subscription need after the initial CARES DG RFP, including the need to supply the proposed Residential DG Community Solar Program.

**Q. WHAT OTHER ENHANCEMENTS HAS THE COMPANY PROPOSED FOR ITS DG RFP?**

A. The Company is proposing two additional enhancements that are new to the DG RFP process. First, the Company proposes adding the option for flexible DG resources that include battery energy storage systems ("BESS") as part of its procurement strategy. Second, the Company is proposing to offer more information to help RFP participants effectively locate projects through the use of locational value as part of the evaluation process.

**Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO FLEXIBLE DG SOLAR PROCUREMENT THAT INCLUDES BESS RESOURCES?**

A. The Company proposes to procure flexible DG resources, with the opportunity to co-locate distribution-connected BESS resources, as part of its DG procurement process. With increasing solar penetration, operational flexibility and control at the distribution level is vital to ensure System reliability. Further, dispatchable BESS resources can deliver much needed capacity to the System and provide value to all customers. The ability to add solar charged or grid charged dispatchable BESS technology to solar facilities will enhance System capabilities and will afford more flexibility and control at the distribution level. Flexible DG resources will be recognized for the additional value delivered as part of the RFP evaluation process.

**Q. WHAT LOCATIONAL GUIDANCE DOES THE COMPANY GIVE DG RFP PARTICIPANTS TODAY?**

A. The Company implemented the statewide solar DG Hosting Capacity Tool in November 2023. This tool is a "heat map" that uses results from different feeder studies to help RFP participants locate potential sites for projects. The System is dynamic and is updated as new resources are added; therefore, the Company updates the Hosting Capacity Tool periodically to reflect such changes. The first annual update to the tool was released in December 2024 and the Company expects to update the tool on a semi-annual basis beginning in 2025.

Additionally, the Company offers interconnection guidance to assist developers in determining the feasibility of installing DG resources within the Georgia Power service territory. Together, the DG Hosting Capacity tool and the Company's existing interconnection guidance help RFP participants site projects in favorable locations.

**Q. WHAT NEW LOCATIONAL VALUE CONSIDERATIONS WOULD THE COMPANY CONSIDER AS PART OF ITS PROPOSED ENHANCEMENT?**

A. The updated RCB Framework introduces new locational value considerations into the Company's evaluation of renewable DG RFP submissions. To aid in the development of renewable DG resources in areas with more favorable interconnection conditions, the Company has replaced the deferred transmission investment component of the RCB Framework, which is applied to all resources regardless of location, with a geographically differentiated transmission system cost benefit factor in the DG RFP evaluation process to ensure the portfolio of resources selected provides the maximum benefits to Georgia Power customers.

**Q. HOW WOULD THE COMPANY DETERMINE LOCATIONAL VALUE UNDER ITS PROPOSED ENHANCEMENT?**

A. The locational value is determined by evaluating two alternative future system scenarios, one with and one without additional DG resources for each identified geographic region. The transmission investments and in service timing of projects are determined for each scenario's study horizon. The resulting differences in transmission project identification and timing are evaluated in an economic analysis that results in a benefit or cost attributed to DG resources.

**Q. HOW WOULD THE PROPOSED LOCATIONAL VALUE CHANGES HELP RFP PARTICIPANTS SITE PROJECTS MORE EFFECTIVELY?**

A. The proposed locational value changes would allow the Company to apply geographically differentiated transmission system costs and benefits to the evaluation process. By communicating those values to RFP participants as they consider project location, the Company expects to receive a portfolio of proposals that offer greater overall value to all customers, which would increase the chance those proposals are selected as winning resources in the procurement process.

***Proposed Renewable Procurements***

**Q. WHAT DOES THE COMPANY SEEK TO PROCURE FROM RENEWABLE RESOURCES AS PART OF THE 2025 IRP?**

A. Through the proposed enhanced procurement processes, the Company is seeking to competitively procure energy from up to 4,000 MW of new renewable resources by 2035, beginning with 1,000 MW from Utility Scale resources through an RFP to be issued in 2026; and 100 MW from DG resources. This amount represents an appropriate level of near-term procurement of new resources as the Company navigates the challenges of renewable integration, while maintaining a long-term renewable target amount that benefits all customers. At this level of procurement, the Company continues its measured and disciplined approach to renewable resource procurement for the benefit of all customers.

**Q. HOW MANY RFPS IS THE COMPANY PROPOSING TO OFFER AND WHEN WILL THEY BE ISSUED?**

A. The Company proposes to issue three RFPs, maintaining a steady cadence of solicitations while also providing for flexibility and adaptability in the procurement processes. First, the Company proposes to issue a Utility Scale RFP in 2026 that targets 1,000 MW of renewable resources anticipated to be online between November 30, 2030, and November 30, 2032, as part of a flexible COD window. Leveraging the proposed multi-phase RFP approach, this procurement would begin with the proposed Phase I of the Utility Scale RFP. To retain the flexibility to meet additional, unmet customer demand, the Company would initiate Phase II of its proposed process to procure up to an additional 3,000 MW by 2035, thus offering the ability for RFP participants and subscribing customers alike to contribute to the cost effectiveness of individual projects and support additional renewable resources.

Second, Georgia Power proposes to issue two DG RFPs, one in 2026 and one in 2027, each seeking 50 MW of resources with commercial operation in 2027, 2028, and 2029. Both DG RFPs would occur under the proposed Phase I of the DG RFP process and would add an additional Phase II procurement opportunity as proposed and if needed to meet customer demand.

The table below summarizes the Company's proposed RFPs:

| **RFP** | **Expected Issuance** | **Target (MW)** | **Expected COD** |
|---|---|---|---|
| Utility Scale | 2026 | 1,000 | 2030–2032 |
| Distributed Generation | 2026 | 50 | 2027–2028 |
| Distributed Generation | 2027 | 50 | 2029 |

**Q. WHAT ADDITIONAL SUM DOES THE COMPANY REQUEST FOR ITS UTILITY SCALE AND DG RFPS?**

A. Consistent with the additional sum approved in the 2022 IRP, the Company requests a levelized $4.00 per kilowatt-year ("kW-yr") AC of the procured amount annually for the term of each PPA entered into as a result of its Utility Scale and DG RFPs. Such an additional sum appropriately incents the Company to competitively procure additional resources and fairly considers lost revenues, changed risks, and an equitable sharing of benefits consistent with the additional sum authorized by statute.[2]

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[2] *See* O.C.G.A. 46-3A-9 ("The approved or actual cost, whichever is less, of any certificated demand-side capacity option shall be recovered by the utility in rates, along with an additional sum as determined by the commission to encourage the development of such resources.").

**Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS RELATED TO ITS RENEWABLE PROCUREMENTS?**

A. Consistent with past practice, the Company proposes to recover the costs related to the procurement of renewable energy through the fuel cost recovery ("FCR") clause. Any participation charges designed to recover associated costs and paid by subscribing customer(s) (as described below) would be applied to the fuel clause to reduce FCR costs.

## IV. RENEWABLE AND RESILIENCY CUSTOMER PROGRAMS

***Customer Renewable Subscription Programs***

**Q. WHY IS THE COMPANY PROPOSING TO MAKE ALL THE ENERGY PROCURED THROUGH THE UTILITY SCALE AND DG RFPS AVAILABLE FOR SUBSCRIPTION?**

A. Many Georgia Power customers continue to express increased interest in renewable energy programs. Consistent with the approach taken in the 2022 IRP and in response to growing customer demand, the Company proposes to continue to make the energy from every MW procured by the Utility Scale and DG RFPs available for subscription by qualifying customers. Through the Company's competitive procurement and subscription processes, renewable energy is procured to the benefit of all customers, while also allowing interested individual customers to access the attributes of these resources directly.

**Q. PLEASE DESCRIBE THE PROPOSED MODIFICATIONS TO THE CARES PROGRAM.**

A. The Company proposes enhancements to the CARES program to increase flexibility, expand customer participation, and align renewable procurement with demand while mitigating financial risks to non-participating customers. The Utility Scale RFP process has been modified to allow for additional procurement opportunities if customer subscription demand is not met through the traditional RFP process, ensuring that interested customers have the opportunity to drive additional renewable procurement beyond initial targets. To improve the subscription process, the Company proposes to refine the NOI process, enabling greater customer participation through a Commission-approved methodology. Subscription terms now range from 10 to 30 years in five-year increments, with customers offered two pricing options: a renewable energy credit ("REC")-based fixed program portfolio charge without an hourly energy credit, or a fixed program charge based on the PPA price with an associated hourly energy credit.

To reduce financial risks to non-participating customers, the pricing methodology for the hourly energy credit will be modified, introducing reimbursement thresholds to ensure fairness and prevent negative impacts to nonparticipants. Increased subscription flexibility has also been incorporated to allow for increased procurement through the Phase I submission refresh process to buy down project costs if customer demand exceeds the initial megawatts procured. This enables additional projects from the competitive tier or target list, as appropriate, to revise their submission prices in a way that maintains or improves overall program benefits. If further subscription needs remain unmet, the RFP process will be extended through the proposed Phase II process to allow additional projects to be submitted for consideration. Through this process, customers would have the option to propose specific renewable resources for procurement through a CIR option, negotiating directly with developers, as well as the ability to subscribe to incremental resources at higher subscription prices that offset higher PPA costs. Successful proposals in this process will result in a PPA between Georgia Power and the facility owner, and a corresponding CARES Customer Agreement between Georgia Power and the subscribing customer. All RECs from these CIRs will be retired on behalf of the subscribing customer.

**Q. PLEASE DESCRIBE THE CARES DG SUBSCRIPTION PROGRAM.**

A. The Company proposes to expand the CARES program by offering subscriptions to resources procured through Georgia Power's DG RFPs. This expansion will provide more Georgia Power customers with the opportunity to participate in the CARES Program, as this part of the program will be available to eligible C&I customers with an aggregate demand between 1 MW and 3 MW, as well as Residential customers. Initial subscriptions will be available to eligible C&I customers from the initial procurement phase of each DG RFP. These customers will participate in the CARES NOI process similar to the Utility Scale CARES program. If C&I customer demand for subscriptions exceeds the MW procured through the DG RFP, the Company will initiate the Phase I submission refresh process (described previously) and Phase II of the DG RFP, if needed.

The DG Community Solar Program will allocate up to 10 MW of the initial 50 MW target from each DG RFP for subscription by residential customers. This Program will provide customers with access to solar from new DG facilities using a simplified CARES subscription methodology. Under this approach, residential customers will subscribe to solar energy through a pricing mechanism based on the PPA price, with energy credits calculated from the average value of the facility's production, factoring in Georgia Power's hourly operating costs of incremental generation per kWh. RECs will be retired on behalf of participating customers based on the actual output of the facilities.

Georgia Power is exploring opportunities to partner with third parties to reduce subscription prices for lower-income customers, thereby enhancing the value proposition for eligible participants. If demand exceeds the available MW allocation for residential customers, or if additional demand for DG subscriptions is identified from other customers, additional resources may be procured through the extended RFP process, which will allow developers the opportunity to bring in new subscribers and drive the need for incremental projects.

***Customer-Sited Renewable Programs***

**Q. DOES THE COMPANY PROPOSE ANY CUSTOMER-SITED RENEWABLE PROGRAMS?**

A. Yes. The Company seeks Commission approval of the Customer-Sited Solar Plus Storage Pilot, which will enhance options for customers interested in installing renewable resources at their premises. Additionally, the Company seeks to modify the existing Customer Connected Solar Program to add storage resources, increase the size of eligible facilities, and allow customers without billing history to participate. These programs expand upon Georgia Power's existing portfolio of customer-sited options to now include storage resources, enhancing customer resiliency and grid value through dispatchable capacity-benefitting resources.

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

A. The Customer-Sited Solar Plus Storage Pilot Program is designed to encourage the installation of solar plus battery storage at residential and small commercial sites. The pilot targets 50 MW of capacity, divided equally into two participation pathways: Customer-Directed and Company-Directed. Participants in either pathway can enroll systems up to 20 kW (residential) or 250 kW (small commercial). The systems will be interconnected behind the meter ("BTM"), can be owned by the participating customer or a third party, and will be dispatched by the Company to deliver capacity value to the System. The pilot aims to improve grid reliability, evaluate customer preferences, and enhance economic viability of dispatchable customer-sited solar-plus-storage resources.

**Q. DESCRIBE EACH PARTICIPATION PATHWAY FOR THE CUSTOMER-SITED SOLAR PLUS STORAGE PILOT.**

A. Under the Customer-Directed model, customers direct the use of the battery and can respond to discrete utility-called events to receive incentive payments. In addition to an annual enrollment incentive of $15/kW, participating customers will receive payments based on the asset performance during called events of $1.50/kWh. New or existing assets are eligible to participate in this program.

Under the Company-Directed model, Georgia Power will monitor and control the BESS and operate it based on System needs. In exchange, customers receive a one-time upfront incentive of $750/kW for a 10-year commitment. Only new assets will be eligible to participate, and systems must pair solar and storage. In both models, the BESS is available for resiliency use by the customer in times of grid outage.

**Q. ARE THERE ANY RATE LIMITATIONS ON WHICH CUSTOMERS CAN PARTICIPATE?**

A. Yes. Although participating customers will retain their rate options, there are two proposed rate limitations: (1) participating residential customers cannot be on the residential ("R") rate, and (2) participating commercial customers cannot be on the general service ("GS") rate. These energy-only rates do not provide an appropriate time-of-use ("TOU") or demand signal to incentivize operation of the solar and battery resources to maximize System benefit. Participating customers will be eligible for other riders, including the renewable and nonrenewable resources ("RNR") rate.

**Q. IS THERE A PARTICIPATION CAP ON THE PILOT?**

A. The Company has not proposed a cap on participation, but rather presented a target enrollment it believes is feasible to implement over the IRP cycle. In the event the Company reaches the target enrollment before the 2028 IRP, the Company will present to the Commission potential program modifications based on lessons learned and seek approval to continue adding interested customers. This "check-in" approach would allow for feedback and learnings to be incorporated without signaling an anticipated end to, or ceiling on, enrollment.

**Q. DID THE COMPANY COLLABORATE WITH STAKEHOLDERS IN DEVELOPING THE SOLAR PLUS STORAGE PILOT?**

A. Yes. The Company participated in two collaboration sessions at the Commission and received additional feedback from participating stakeholders following those meetings. In addition, the Company had conversations with original equipment manufacturers ("OEMs"), installers, program facilitators, sources of potential complimentary funding, and customers. The Company also reviewed peer programs and talked with other utilities in the development process.

**Q. DOES THE PILOT PROGRAM DESIGN ADDRESS FEEDBACK THE COMPANY RECEIVED THROUGH THE COLLABORATION PROCESS?**

A. Yes. As described more fully in the IRP Main Document, the pilot program features a hybrid of upfront and ongoing compensation with incentives that are clear and simple to understand. As proposed, the pilot program allows for broad customer participation including those enrolled in time-varying rates, the RNR tariff, and other utility programs, and includes special consideration for low to moderate income customers. The pilot will leverage the battery inverter for measuring performance and does not penalize customers for non-performance. The program will support participation from multiple battery manufacturers; standalone storage; and existing systems. The pilot ensures at least 20% of battery capacity remains available for local resiliency, and provides for optionality to meet individual needs. By incorporating program design elements in consideration of direct feedback from stakeholders, that Company seeks to deliver a program that meets System, market, and customer needs.

**Q. HOW DID THE COMPANY DETERMINE THE INCENTIVE VALUES TO BE OFFERED FOR PROGRAM PARTICIPATION?**

A. The incentive values were calculated based on the forecasted avoided generation capacity value associated with assets participating in each pathway. The net present value over the term was discounted to 75%, applying a shared savings model consistent with other DER programs. The Company intends this design to ensure participating customers receive sufficient incentive to install dispatchable resources and participate in the program, while also ensuring non-participating customers receive value and do not subsidize implementation and program administration costs.

In recognition of the unique needs of low-to-moderate income residential and municipal, university, school and hospital ("MUSH") commercial customers, the discount factor was not applied to derive incentives for customers in these segments. Further, the program was designed to allow and enable stacking of additional funding sources including resources specifically targeting these groups of customers.

**Q. WHAT DOES THE COMPANY HOPE TO LEARN OR ACHIEVE THROUGH THIS PILOT PROGRAM?**

A. The Company has designed the Customer-Sited Solar Plus Storage Pilot Program to provide the Company with valuable information regarding the technical capabilities, value, and market acceptance of customer-sited solar plus storage.

Additionally, as described in the Main panel, the Company has requested enhanced control through its Distributed Energy Resource Management System ("DERMS"). The parallel participation pathways allow for validation of the benefits accompanying enhanced control. The Company's DERMS will have the capability to dispatch DERs within program parameters, such that the Company will be able to optimize the operation to realize anticipated capacity value and explore additional use cases for solar plus storage and other programs.

**Q. PLEASE DESCRIBE THE PROPOSED MODIFICATIONS TO THE CUSTOMER CONNECTED SOLAR PROGRAM.**

A. Georgia Power proposes modifying the Customer Connected Solar Program by (1) increasing the facility site criteria to a 250 kW minimum and 6 MW maximum, (2) expanding the resource types to include BESS co-located with solar, and (3) allowing new customers to participate. The proposed enhancements are driven by stakeholder feedback. By expanding the eligibility criteria, the Company aims to fill the remaining 23+ MW to meet customer resiliency needs through this expanded front of the meter option. The capacity value created by the dispatchable storage systems will benefit all Georgia Power customers through enhanced reliability and affordability, will support customer resiliency goals, and support the growth of a sustainable customer-sited DG market in Georgia.

***Other Customer Renewable Program Options***

**Q. ARE THE CARES SUBSCRIPTION AND CUSTOMER-SITED PROGRAMS THE ONLY OPTIONS AVAILABLE FOR CUSTOMERS TO SUPPORT RENEWABLE RESOURCES?**

A. No. As stated in the 2025 IRP Main Document, customers will continue to have options to offset their own energy consumption using BTM customer-sited resources, offset their own energy consumption and sell any excess output through the RNR tariff, participate in Community Solar or one of the Company's REC purchase programs, or sell renewable energy to Georgia Power as a Qualifying Facility ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Georgia Power has interconnected more than 12,000 solar projects to date, including customer generators who choose to offset energy usage with BTM solar installations, through RNR or as a QF.

**Q. IS THE COMPANY PROPOSING TO MAKE ANY CHANGES TO THE COMMUNITY SOLAR PROGRAM?**

A. No, Georgia Power is not requesting any modifications to the existing Community Solar Program. However, as described above, the Company has proposed the new DG Community Solar Program as an additional subscription option for residential customers.

**Q. PLEASE DESCRIBE GEORGIA POWER'S EXISTING CUSTOMER-SITED RENEWABLE PROGRAMS.**

A. The Company interconnects and receives energy from customer generators through several Commission approved options. The Energy Offset option exists for customers who wish to install on-site generation without compensation for energy pushed back to the grid. The RNR program enrolls customer generators who offset some of their usage with renewable energy generated onsite and compensates these generators for energy pushed back to the grid at the Company's Renewable Cost Benefit adjusted Solar Avoided cost, plus a $0.04 adder pursuant to the 2022 Rate Case. This adder creates additional costs for all customers as it pays customer generators more than the Company's avoided cost for this energy. Approximately 5,000 customer generators are compensated at retail rates for all the energy produced from customer sited generation through the fully subscribed Monthly Netting program. This program also creates significant upward rate pressure for non-participating customers by compensating above the avoided cost value. Finally, the Company complies with its purchase obligations pursuant to PURPA through standard offer purchases from QFs. The pricing for these transactions is based on the Company's projected day ahead hourly avoided costs and holds other customers harmless.

**Q. PLEASE DESCRIBE THE EXISTING REC PROGRAMS.**

A. The Simple Solar Program is available to residential, commercial, and industrial customers, allowing them to match either 50% or 100% of their monthly energy usage with solar RECs retired on their behalf. The program operates on a monthly basis with no long-term commitment required. Since its launch in 2022, it has consistently served around 1,800 customers, resulting in approximately 27,000 RECs being retired annually.

The Flex REC Program originated in the 2022 IRP as a replacement for the Simple Solar Large Volume program. It enables Georgia Power to procure larger quantities of RECs to meet increasing customer demand. This program sources RECs from a diverse range of renewable resources, including solar and wind, and potentially other renewable sources. Since its inception, Flex REC has maintained an average of 16 customers per month, retiring about 300,000 RECs annually on behalf of participating customers.

The Retail REC Retirement ("R3") program is designed for C&I customers who wish to claim renewable benefits from certain existing renewable resources. It allows these customers to subscribe to RECs from System resources that are either already operational or under construction. The RECs and associated environmental attributes, which would typically be retired on behalf of all customers, are instead retired specifically on behalf of the participating customer. Currently, there are no participants in this program, but it is expected to become a viable option as more customers aim to meet their carbon reduction goals within the next five years.

The Company is not proposing any modifications to these programs at this time.

***Existing Customer Resiliency Programs***

**Q. PLEASE DESCRIBE THE DER CUSTOMER PILOT PROGRAM THAT THE COMMISSION APPROVED IN THE 2022 IRP.**

A. Following the 2022 IRP, the Company developed the DER Customer Pilot Program alongside Commission Staff and intervenors, resulting in the Resiliency Asset Service ("RAS-1") and Demand Response Credit ("DRC-1") tariffs. These tariffs, approved in January 2023, provide a framework for customers seeking resiliency-focused solutions. For customers participating on RAS-1, Georgia Power will install and operate a dispatchable DER behind the customer's meter. Participating customers pay a monthly service charge for that resiliency benefit. Customers participating in RAST-1 also have the option to participate in DRC-1, in which Georgia Power will provide a credit in exchange for the Company's ability to use the DER for demand response during System reliability events.

**Q. PLEASE DESCRIBE THE DER COLOCATION PROGRAM THAT THE COMMISSION APPROVED IN THE 2023 IRP UPDATE.**

A. The DER Colocation program, as approved in the 2023 IRP Update Order, is an optional tariff available to qualifying C&I customers. Under this program, Georgia Power owns, operates, maintains, and controls dispatchable DERs located on customer premises, which are then economically dispatched to provide energy and capacity benefits to all customers. The DER systems are interconnected to the electric grid, allowing for energy transmission while also serving as a resiliency resource for participating customers during outages. Participating customers pay rates that ensure the DER investment remains below its system value, thereby providing financial benefits to all customers. The DER technology used in this program may include combustion turbines, reciprocating internal combustion engines ("RICE"), and other dispatchable technology with a firm fuel supply.

**Q. PLEASE DESCRIBE THE DER CUSTOMER-OWNED PROGRAM THAT THE COMMISSION APPROVED IN THE 2023 IRP UPDATE.**

A. The DER Customer-Owned Program is an optional program designed for qualifying C&I customers who own dispatchable DERs less than 10 MW. Under the DER Customer-Owned tariff ("DCO-1"), participating customers receive bill credits based on the capacity and energy value of their DERs. The program ensures that DER interconnections support the electric grid while also providing backup power during outages. Similar to the DER Colocation Program, a key difference under the DER Customer-Owned Program is that the customer retains ownership of the DER asset, while Georgia Power operates and controls the resource for economic dispatch.

**Q. WHAT ARE THE COMPANY'S OBJECTIVES IN OFFERING THESE DER PROGRAMS TO CUSTOMERS?**

A. DER programs are an important component of the Company's portfolio of customer programs. The Company is in regular communication with customers and continues to modify its suite of DER options to better align with customer interest and Company needs. The design of the Company's DER programs is intended to maximize mutual benefits among customers looking to make these types of onsite investments while leveraging the resilience and reliability benefits to the grid and all retail customers. In addition, the Company aims to encourage customers considering adding these resources to adopt cleaner resources.

**Q. ARE ANY CUSTOMERS ENROLLED ON THESE DER TARIFFS?**

A. Not yet, but the Company is working closely with customers to move forward with projects on its DER tariffs. Discussions are ongoing and several potential customers have progressed to evaluating contract language and site design elements.

**Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO EXISTING DER PROGRAMS?**

A. Georgia Power is seeking to modify the DER Customer-Owned Program in the 2025 IRP to allow contract terms up to 15 years. Previous tariff language restricted contracts through 2031. Extending the potential contract duration increases the value proposition for both participating and non-participating customers. Participating customers will have increased certainty on the value stream to justify additional costs associated with participation. Non-participating customers receive the benefits of capacity locked in and procured at a discounted rate for an extended duration.

***<u>Proposed Customer Resiliency Program</u>***

**Q. PLEASE DESCRIBE THE LARGE CUSTOMER OWNED RESILIENCY PROGRAM THAT GEORGIA POWER IS PROPOSING IN THE 2025 IRP.**

A. The LCOR Program is a newly proposed program aimed at transmission-connected C&I customers. This program allows these customers to retain ownership of their DER assets while providing Georgia Power with operational certainty that contracted response will materialize when called upon by the Company for utility use. These assets are not intended to push back onto the grid and the resources do not need to be separately metered. Participating customers will be responsible for all fuel and O&M costs associated with the assets. As with the Company’s other DER programs, assets must be dispatchable with firm fuel supply and permitted for non-emergency use. By expanding its DER offerings, Georgia Power aims to provide a robust portfolio of options for customers with diverse energy needs while ensuring grid resilience and affordability.

**Q. WHAT ARE THE BENEFITS OF THE LCOR PROGRAM?**

A. Benefits of the LCOR Program include:

- Economic Compensation: Participating customers are compensated for providing firm load reductions to the System and Georgia Power's need for additional capital expenditures is reduced.
- Faster Capacity Recognition: Unlike the supply-side DER programs that are subject to FERC-dictated interconnection timelines and requirements, this program accelerates the timeframe in which co-located resources can be utilized to meet capacity needs.
- Reliability Enhancement: The program ensures that load reductions materialize when needed, reducing uncertainty, increasing efficiency, and improving grid stability.
- Cost Savings for Non-Participants: Since the program operates under a shared savings model, the cost of procuring capacity is lower than traditional generation expansion, reducing costs for all customers.

**Q. WHICH CUSTOMERS ARE ELIGIBLE TO PARTICIPATE IN THE LCOR PROGRAM?**

A. The LCOR Program is designed for large C&I customers who meet the following eligibility criteria:

- Customers must own and operate dispatchable DERs with a firm fuel supply permitted for non-emergency use.
- The DERs must be connected to Georgia Power's grid and be available to respond based on System needs during a contracted number of hours.
- Customers must enter into a contractual agreement with Georgia Power to provide demand response contributions.
- Participants must meet the minimum capacity commitment during events as defined in the customer contract.

This program is particularly suited for businesses with critical energy needs, such as data centers, manufacturing facilities, hospitals, and logistics hubs, where backup power and load flexibility can be leveraged for grid resiliency.

***Electric Transportation***

**Q. WHAT IS VEHICLE-TO-EVERYTHING TECHNOLOGY?**

A. Vehicle-to-everything ("V2X") technology refers to the use of bi-directional charging technology that enables electric vehicles ("EVs") to transfer energy stored in their batteries back to buildings, houses, or the grid. With increasing EV deployment, a significant number of batteries will be in the market, and unused energy in those batteries could be beneficial as a grid asset.

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR A VEHICLE TO GRID PILOT PROGRAM.**

A. The Company seeks to install up to 10 bi-directional chargers for a grid-specific, or V2G, pilot program across up to four customer locations. The pilot will be available to public school systems served by Georgia Power that utilize or plan to utilize electric school buses as part of their fleet.

**Q. WHY IS A V2G SCHOOL BUS PILOT AN APPROPRIATE STARTING POINT TO EXPLORE V2X TECHNOLOGY?**

A. School systems are particularly well-suited for V2G pilot programs for several reasons. First, school buses have regular, predictable schedules. They are typically in use during the morning and afternoon, idle for long periods during the day and overnight, and may not be in use at all during summer peak periods. This predictability makes it easier to manage charging and discharging cycles and utilize electric buses as a grid resource without impacting the school customer's transportation availability.

Second, school buses have large batteries that can store significant amounts of energy. This makes them ideal for providing substantial power back to the grid during peak demand times, and the scale of available capacity justifies interconnection and equipment costs.

Third, school systems have already purchased electric buses and expressed interest in participating in a Georgia Power V2G program. Stakeholders submitted a V2G bus pilot idea as part of the DSMWG, and other utilities have launched pilots that can serve as a guide for implementation. Finally implementing V2G technology in school systems can serve as a model for other community-based projects, promoting broader adoption and awareness of V2G capabilities.

**Q. WHAT DOES THE COMPANY HOPE TO LEARN FROM THE V2G PILOT?**

A. The Company hopes to gain a better understanding of the infrastructure costs required to support V2G and the ongoing costs to manage and administer such technology. The Company also seeks to learn about the capabilities of V2G and the value of vehicles as a grid resource to provide capacity during peak periods and other use cases. Finally, the Company seeks to understand how customer behavior and preferences will impact the potential for vehicles to serve as a reliable grid resource while being used primarily as a transportation solution.

## V. CONCLUSION

**Q. WHAT ARE GEORGIA POWER'S REQUESTS FOR RENEWABLE RESOURCE PROCUREMENTS IN THIS CASE?**

A. Georgia Power seeks Commission approval of the following renewable resource procurement requests:

1. The updated Utility Scale RFP process to procure energy from 1,000 MW of new Utility Scale renewable energy resources, along with the ability to procure additional resources above the initial MW target to meet the needs of subscribing customers.

2. The updated DG RFP process to procure energy from 100 MW of new DG solar resources through two separate RFPs (50 MW each), including the

incorporation of locational value in DG procurement evaluations and the ability to procure additional resources above the initial MW targets to meet the needs of subscribing customers.

3. The levelized additional sum of $4.00 / kW-yr AC of 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.

**Q. WHAT ARE GEORGIA POWER'S REQUESTS AS IT RELATES TO CUSTOMER PROGRAMS IN THIS CASE?**

A. Georgia Power seeks Commission approval of the following requests regarding its DSM Action Plan for the Proposed Case, DER Resiliency Programs, and customer renewable programs:

**DSM:**

1. Grant a certificate for the Residential Products program.
2. Decertify the Residential Refrigerator Recycling Plus program, the Residential Specialty Lighting program, and the Commercial Behavioral program.
3. Amend the certificate for four (4) previously certified programs:
   - i. the Residential Behavioral program;
   - ii. the Residential Demand Response program;
   - iii. the Commercial Prescriptive Program; and
   - iv. the Small Commercial Direct Install program.
4. Grant a waiver of the TRC requirement within Commission Rule 515-3-4-.04(4)(a)(3) for four (4) previously certified programs:
   - i. the Residential HopeWorks program;
   - ii. the Residential Home Energy Improvement program;
   - iii. the Residential Energy Assistance for Savings and Efficiency program; and
   - iv. the Commercial Custom program.
5. Approve the updated program economics for all previously certified DSM programs.

6. Approve the revised additional sum calculation methodology collected through the DSM programs certified in the 2025 DSM Application.

7. Approve the Company's other DSM activities as further specified in the Company's 2025 IRP in Docket No. 56002, including the Energy Efficiency Awareness Initiative, pilot studies, and Learning Power Education Initiative.

**DER Resiliency Programs:**

1. Approve the modification of the DER Customer Owned Program to allow contracting up to 15 years.

2. Approve the new Large Customer Owned Resiliency Program as described in the 2025 IRP.

3. Approve an additional sum of $4/kW-year AC for new demand response and new DER programs, including the Large Customer Owned Resiliency Program, Solar + Storage Pilot Program, and modified Customer Connected Solar Program.

4. Approve the V2G Pilot.

**Customer Renewable Programs:**

1. Approve the enhanced CARES subscription program, including the ability for participating customers to subscribe to smaller, DG resources; the opportunity for residential customers to subscribe through the DG Community Solar Program; more flexible participation provisions; and the ability for customers to identify renewable resources to be considered for procurement, as described in the 2025 IRP.

2. Approve modifications to the Customer Connected Solar Program as described in the 2025 IRP.

3. Approve the small commercial and residential Customer-Sited Solar Plus Storage Pilot Program as described in the 2025 IRP.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

# CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing GEORGIA POWER COMPANY'S 2025 INTEGRATED RESOURCE PLAN in DOCKET NO. 56002 upon all parties listed below via electronic service or by hand delivery and addressed as follows:


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This 28th day of February, 2025.

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## CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing GEORGIA POWER COMPANY'S 2025 APPLICATION FOR CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND-SIDE MANAGEMENT PLAN IN DOCKET NO. 56003 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

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