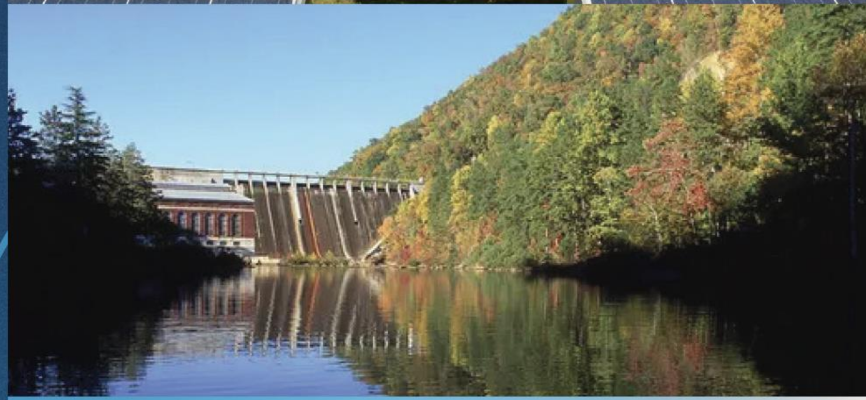
Docket No. **56002**

2025 Integrated Resource Plan

January 2025



Georgia Power

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

- Application for Certification of Capacity from Plant Scherer Unit 3
- Application to Amend the Certificate of Capacity from Plant McIntosh Units 10-11 and 1A-8A

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Executive Summary

Georgia Power Company ("Georgia Power" or the "Company") files this 2025 Integrated Resource Plan ("2025 IRP") in accordance with the Official Code of Georgia Annotated[1] and the Georgia Public Service Commission ("Commission") Rules and Regulations.[2] Consistent with prior Integrated Resource Plans ("IRPs"), Georgia Power continues to focus on providing clean, safe, reliable, and affordable electric service to its more than 2.8 million customers. Serving customers and supporting a growing Georgia are key principles of the Company's integrated resource planning process, and Georgia Power is committed to maintaining reliability and affordability for all customers. In this IRP, the Company proposes necessary investments in its generation fleet and transmission system to ensure Georgia Power can continue to serve its customers with the reliability and resiliency they deserve and expect. The Company is also proposing innovative solutions that will enhance the value of customer programs and enable System-wide control of distributed energy resources ("DERs"), which will strengthen the capabilities of the electric system and help meet customers' evolving energy needs. 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.

Continued Load Growth

Georgia continues to be a top state in which to do business. As the Company continues to see positive economic development trends throughout the state, the 2025 IRP utilizes a risk-adjusted load forecasting process similar to the process used in the 2023 IRP Update. To support its load forecasting processes, Georgia Power maintains active engagement and discussions with large load customers, ensuring appropriate refinements with updated data, timelines, and projections. The 2025 IRP contains an updated load forecast that addresses recent economic development trends since the 2023 IRP Update, as well as specific information for the Company's growing pipeline of potential and committed large load customers. Georgia Power's risk-adjusted load forecast from the winter of 2024/2025[3] through the winter of 2030/2031 reflects approximately 8,200 MW of load growth, representing an increase of more than 2,200 MW compared to 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.

Demand-Side Strategy

Georgia Power's demand-side management ("DSM") portfolio remains an important component of its resource mix. In this IRP, the Company's DSM portfolio consists of demand response programs, energy efficiency programs and pilots, and other DSM activities. Consistent with prior IRPs and

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[1] O.C.G.A. § 46-3A-2.

[2] Subject 515-3-4 Integrated Resource Planning.

[3] 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.

Commission policy, the Company continues to treat energy efficiency as a priority resource and works closely with the Commission Staff and the DSM Working Group ("DSMWG") using the approved Demand-Side Management Program Planning Approach for program development. Additionally, in accordance with the Commission's Order Adopting Stipulation in the Vogtle Prudency Proceeding in Docket No. 29849 ("Vogtle Prudence Order"), the Company developed the DSM Proposed Case with a savings target of at least 0.75% of annual retail sales.

The Company has identified the continued need for important DSM resources while appropriately considering the increasing cost to achieve additional savings. Even though avoided energy costs have increased since the 2022 IRP, which has a positive impact on energy efficiency economics, both Total Resource Cost ("TRC") and Rate Impact Measure ("RIM") test results have declined primarily due to the substantial amount of resources needed to achieve high energy savings resulting from the Vogtle Prudence Order. 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. Nevertheless, in light of DSM program benefits, the Company supports the continuation of several of its DSM programs in this IRP. These programs are designed to enhance energy efficiency and provide customers with more control over their energy usage. Building on the momentum from the 2022 IRP, Georgia Power continues to focus on offering additional DSM options for income-qualified customers.

Supply-Side Extensions and Upgrades

The 2025 IRP supply-side plan includes an update to the Company's Reserve Margin Study and a corresponding increase in the summer Target Reserve Margin to maintain the level of reliability customers and the state deserve and expect. As the state continues to grow, Georgia Power is committed to maintaining reliable and economical electric service, and the Company must continue to invest in its foundational resources, which includes continuing the operation of Plant Bowen Units 1-4, extending the operation of approximately 1,100 MW at Plants Scherer and Gaston, upgrades of up to 400 MW to nuclear and natural gas units, and the continued investment to maintain and operate more than 650 MW of hydroelectric resources at nine facilities. Adding new incremental capacity through upgrades at existing facilities, such as Plants Hatch, Vogtle, and McIntosh, demonstrates the importance and economic value of utilizing existing facilities to meet customers' needs and support growth in a reliable and economical manner. With the proposed operational extensions of existing coal and gas steam units through the mid-2030s, the Southern Company System ("System") gains resource planning flexibility in a dynamic federal environmental regulatory landscape. The Company's Environmental Compliance Strategy ("ECS") and Unit Retirement Study detail the Company's plans for compliance with environmental requirements, including the 111 Greenhouse Gas Rules ("111 GHG Rules"). The Company's continued investment in its hydroelectric facilities enables the continued long-term operation of these valuable, dispatchable, and emissions-free resources.

Through 2031, Georgia Power projects a capacity need of 9,000 MW, and the Company plans to meet that need through approved actions from 2022 IRP, 2023 IRP Update, and the incremental requests in this 2025 IRP, which include unit extensions, upgrades, hydro modernization, additional RFPs, and demand side programs. Georgia Power is addressing capacity needs through the winter of 2030/2031 through actions approved by the Commission in the 2022 IRP and 2023 IRP Update. For example, current activities include the addition of more than 2,065 MW of battery energy storage systems ("BESS") and combustion turbine ("CT") resources by the end of 2027, plus the Company's active RFPs for up to 9,500 MW of capacity and more than 3,500 MW of renewable energy resources by the end of 2030. To address capacity needs beyond 2031, the Company plans to conduct All-Source Capacity Requests for Proposals ("RFP") including issuing an RFP in the third quarter of 2025 to meet capacity needs for 2032 and 2033, while also seeking to add up to 4,000 MW of incremental renewable resources to the electric system by 2035.

Serving customers' evolving energy needs requires a diversified approach. Georgia Power's proposed economical extensions and enhancements to existing generating units and new procurements are necessary to ensure reliable and economic service to existing customers and a growing Georgia.

Strategic Transmission Planning

The Company is dedicated to maintaining a robust and reliable electrical system. 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. The 2025 IRP includes (i) the 2024 Georgia Integrated Transmission System ("ITS") Ten-Year Plan, which incorporates generation and load growth updates for Georgia Power, Georgia Transmission Corporation ("GTC"), Municipal Electric Authority of Georgia ("MEAG Power"), and Dalton Utilities (collectively, the "ITS Participants"), 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.

Enhanced Renewable and Resiliency Programs

As part of this 2025 IRP, Georgia Power proposes innovative solutions to meet increasing customer demand for emission-free, sustainable, and resilient energy. These proposed solutions include expanding the Company's customer subscription programs to include distributed generation ("DG") renewable resources and enhancing the utility-scale ("US") and DG renewable procurement processes to facilitate the addition of more renewable resources available for customer subscriptions. Notably, these programs are available to residential, commercial, and industrial customers. The Company is committed to supporting flexibility, optionality, and innovation in its planning and program offerings, especially as the energy industry continues to see dynamic change along many fronts.

Georgia Power is also proposing a new customer-sited solar plus storage program for residential and small commercial customers and adding a new DER-enabled demand response program aimed at meeting the capacity and resiliency needs of large customers. To enable these programs and to create visibility, enhance forecasting, and allow System-wide control of DERs, Georgia Power is developing and deploying a Distributed Energy Resource Management System ("DERMS"). By integrating DERMS, the Company is enhancing System controls to optimize the operational capabilities of the next-generation grid and energy assets and ensuring the Company remains at the forefront of technological advancements for the benefit of customers.

Conclusion

The 2025 IRP proposes a reliable, economical, and diverse resource mix that will ensure Georgia Power can continue to meet its customers' evolving energy needs. The Company is utilizing a combination of previously approved RFPs and incremental requests of up to 1,500 MW in this IRP to meet load growth of approximately 8,200 MW through the winter of 2030/2031, and is proposing new procurements to address capacity and energy needs into the 2030s. As the energy industry experiences rapid change on numerous fronts, Georgia Power continues to utilize a scenario planning process that provides for flexibility, optionality, and innovation. The 2025 IRP leverages new and innovative customer programs, enhanced generation procurement processes, strategic transmission planning, opportunities afforded by existing generation resources, and new demand-side and distributed energy options, all for the benefit of customers.

Georgia Power is proud to serve Georgia's communities, and the Company's commitment to its customers remains the cornerstone of its business. As set forth in this 2025 IRP, the Company will continue working constructively with the Commission to invest in Georgia's energy future and provide customers with the clean, safe, reliable, and affordable electric service they deserve and expect.

The Company respectfully requests that the Commission approve the 2025 IRP and each of the following items:

1. The Reserve Margin Study, as provided in Technical Appendix Volume 1, and the Company's recommended System long-term winter Target Reserve Margin value of 26%, long-term summer Target Reserve Margin value of 20%, and the short-term Target Reserve Margins associated with each season.
2. A certificate of public convenience and necessity for one new DSM program, decertification of three DSM programs, amended certificates for four DSM programs, amended certificates and waiver of the total resource cost ("TRC") requirement[4] for four previously certified DSM programs, and approval of updated program economics for all other previously certified DSM programs, for the Proposed Case as specified in the Company's Application for Certification, Decertification, and Amended Demand-Side Management Plant ("2025 DSM Application"), Docket No. 56003.
3. The revised calculation of the additional sum collected through DSM programs certified in the 2025 DSM Application, Docket No. 56003.
4. Approval of proposed modifications to the existing DER programs as described in Chapter 10.
5. Approval of a new large Customer Owned Resiliency program as described in Chapter 10.
6. Approval of the levelized additional sum of $4.00 / kilowatt ("kW") alternating current ("AC") of the total capacity amount from new demand response and new DER programs, including the large Customer Owned Resiliency Program, Solar Plus Storage Pilot Program, and modified Customer Connected Solar Program ("CCSP").

[4] Commission Rule 515-3-4-.04(4)(a)(3) states that measures which fail the Total Resource Cost test shall be eliminated from program consideration.

7. Extended operation of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and A beyond December 31, 2028, as described in Chapter 8.
8. Certification of wholesale capacity from Plant Scherer Unit 3 to be placed in retail rate base, as specified in Attachment A.
9. Amendment to the certificate at Plant McIntosh Units 10-11 and 1A-8A for incremental capacity, as specified in Attachment B.
10. Approval of incremental capacity at Plant Hatch Units 1-2 and Plant Vogtle Units 1-2, as specified in Chapter 8.
11. The capital and operations and maintenance ("O&M") costs (but not yet the recovery of such costs) the Company will incur for the modernization of Plants Tallulah, Yonah, Lloyd Shoals, Wallace, Bartletts Ferry Units 5-6, Goat Rock, North Highlands, Morgan Falls, and Flint River hydro facilities, as specified in the Hydro Modernization section of Technical Appendix Volume 1.
12. Authority to develop, own, and operate incremental capacity at Plant Goat Rock Units 3-6, as specified in Chapter 8 and the Hydro Modernization section of Technical Appendix Volume 1.
13. The capital, O&M, and coal combustion residual asset retirement obligation ("CCR ARO") costs (but not yet the recovery of such costs) and associated measures taken to comply with government-imposed environmental mandates, as specified in the ECS in Technical Appendix Volume 1 and the Environmental Compliance Cost Recovery ("ECCR") and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 2.
14. The authority to pursue the natural gas co-firing compliance pathway as the 111 GHG Rule strategy for Plant Bowen and Plant Scherer.
15. 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, as described in Chapter 8 and Chapter 10.
16. The updated Distributed Generation RFP process to procure energy from 100 MW of new Distributed Generation solar resources through two separate RFPs (50 MW each), along with the ability to procure additional resources above the initial MW targets to meet the needs of subscribing customers, as described in Chapter 8 and Chapter 10.
17. 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.
18. The updated Renewable Integration Study and its use in planning processes, as specified in Technical Appendix Volume 2.
19. The updated Renewable Cost Benefit ("RCB") Framework, including incorporation of locational value in DG procurement evaluations, as specified in Technical Appendix Volume 2.

20. The enhanced Clean and Renewable Energy Subscription ("CARES") program, including the ability for participating customers to subscribe to smaller, distributed generation resources; the opportunity for Residential customers to subscribe through the Distributed Generation Community Solar Program; more flexible participation provisions; an updated subscription methodology; and the ability for customers to identify renewable resources to be considered for procurement, as described in Chapter 10.
21. The small commercial and residential customer Solar Plus Storage Pilot Program, as described in Chapter 8 and Chapter 10.
22. Modifications to CCSP, including the ability to add storage resources, as described in Chapter 10.
23. Enhanced control of DER assets through the Company's DERMS to ensure grid reliability, enable, and optimize DER grid support functions, as described in Chapter 10.
24. Approval of the Electric Transportation Vehicle-to-Everything ("V2X") Pilot, as described in Chapter 10.

Chapter 1. Company Overview

Georgia Power, a wholly owned subsidiary of Southern Company, is an investor-owned electric utility that serves approximately 2.8 million retail customers in all but three of Georgia's 159 counties. Georgia Power electric service is available in 57,000 of the state's 59,000 square miles.

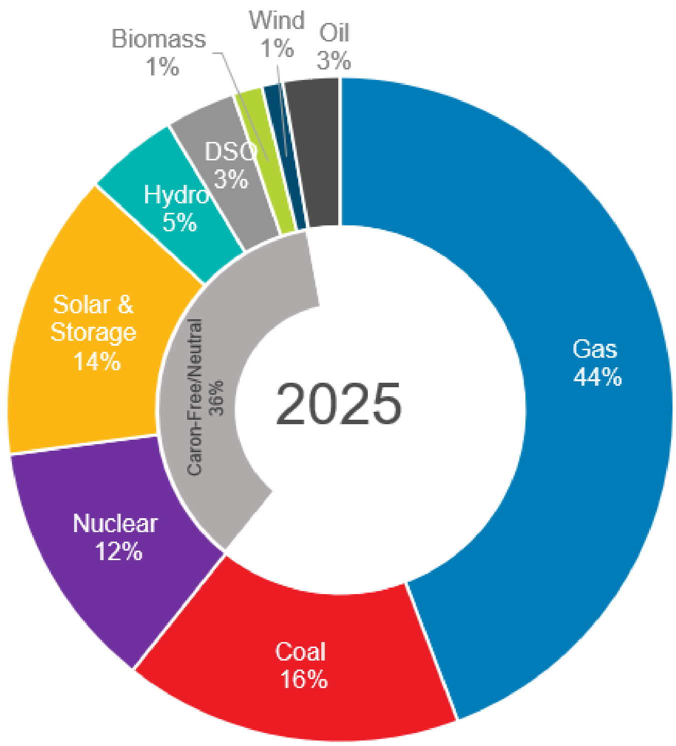
Southern Company is the parent of Georgia Power, Alabama Power Company ("Alabama Power"), Mississippi Power Company ("Mississippi Power"), Southern Power Company ("Southern Power"), and Southern Company Gas (formerly AGL Resources Inc.). Except where otherwise noted, Alabama Power, Georgia Power, and Mississippi Power (collectively, the "Retail Operating Companies") as well as Southern Power are considered the electric "Operating Companies" for this 2025 IRP. The Operating Companies operate their respective electric generating facilities and conduct their system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of an interchange contract among themselves. This is further described in Attachment G. The Retail Operating Companies are members of the Southeastern Electric Reliability Council ("SERC"), a group of electric utilities (and other electric-related utilities) coordinating operations and other measures to maintain a high level of reliability for the electrical system in the Southeastern United States ("U.S.").

As of December 31, 2024, Georgia Power has ownership in 136 retail-serving generating units, including 5 combined cycle ("CC"), 13 fossil steam, 6 nuclear, 15 renewable, 66 hydro, 1 BESS, and 30 CT or diesel engine units, of which at least two have seasonal usage restrictions. Plant sites are specified in Figure 1A for those units located in Georgia.

Figure 1A: Map of Georgia Power Owned Supply-Side Resources

Georgia Power meets retail customer peak demands and energy requirements through a diverse portfolio of the Company-owned resources shown above, plus power purchase agreements ("PPAs"), and dispatchable demand-side options ("DSOs"). Figure 1B below demonstrates Georgia Power's projected capacity mix for 2025. This capacity mix reflects the relative share of maximum power output for each resource type. Resource-specific capacity information can be found in Attachment C as well as the Resource Mix Study in Technical Appendix Volume 2.

Figure 1B: Georgia Power's Projected Summer 2025 Capacity Mix[5]

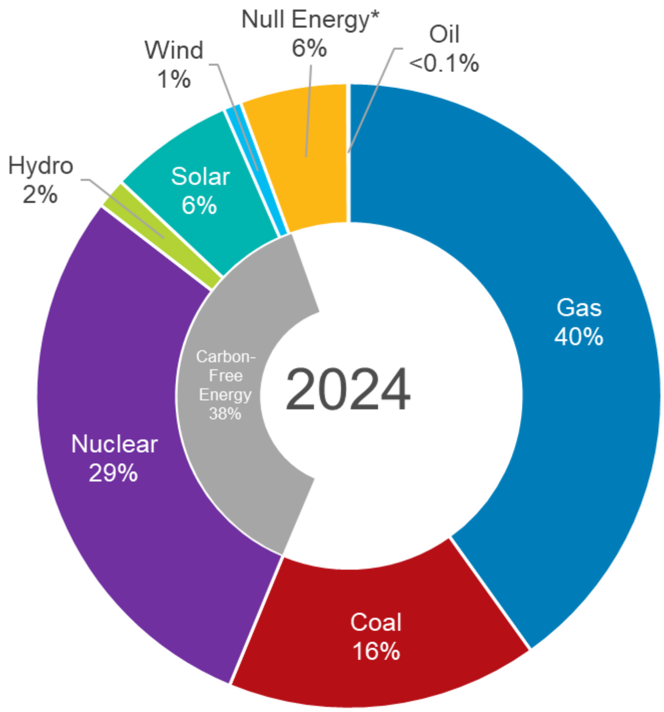


The capacity mix conveys the total power that could be produced by resources in a given moment with ideal operating conditions, and the Company's energy mix reflects the actual dispatch of resources over a certain period. Of the energy generated to meet Georgia Power's retail customers' needs in 2024, 40% was from natural gas, 16% from coal, 29% from nuclear, 7% from renewables, 2% from hydro, 6% categorized as null energy,[6] and less than 1% from oil-fired resources. Actual generation is influenced by several factors, such as production cost, weather, and reliability needs. The Company's 2024 energy mix is provided in Figure 1C below.

[5] This figure includes Georgia Power's existing, planned, and committed resources and reflects demonstrated retail capacity for traditional resources, nameplate capacity for retail-serving renewable resources, and program capacity for dispatchable DSOs. It does not reflect generic expansion plan resources. A portion of the renewable generation capacity accounted for in this chart includes capacity for which the rights to renewable energy credits ("RECs") are retained by third-party generators or subscribing customers.

[6] Null energy is the underlying unspecified and undifferentiated power remaining when renewable or other environmental attributes like RECs have been separated and removed.

Figure 1C: Georgia Power's 2024 Energy Mix[7]



[7] Georgia Power purchases only the null energy output and not RECs from some renewable generating facilities. The rights to RECs are addressed by the applicable PPA. The party that owns the RECs retains the right to make renewable energy claims in connection with the RECs.

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Chapter 2. Implementation of Prior IRPs

2.1 – 2023 IRP Update

The Company's 2023 IRP Update was approved with modifications as specified in the Commission's March 26, 2024, Order Adopting Stipulated Agreement in Docket No. 55378 ("2023 IRP Update Order"). Consistent with the 2023 IRP Update Order, the Company has taken or will take the following actions:

1. Provided Commission Staff with three quarterly reports providing updates on large load economic development activity from the 2023 IRP Update Load Forecast beginning May 15, 2024.
2. Submitted an expedited certification application for the 500 MW Company-owned BESS resources on August 16, 2024. The Company and Commission Staff reached a settlement resolving all issues in the case, and public hearings regarding the matter were held on October 31, 2024. The Commission approved the certification of the Moody, Robins, Hammond, and McGrau Ford Phase II BESS projects on December 12, 2024.
3. Issued the Winter 2027/2028 BESS RFP to the market on August 9, 2024, for the additional BESS resources that are needed during the winter of 2027/2028 based on the 2025 IRP Load Forecast. Bids were due on September 16, 2024, and the competitive tier was identified on October 10, 2024. Capacity needs are currently expected to exceed the 500 MW projected during the 2023 IRP Update. The Company is evaluating the results of the Winter 2027/2028 BESS RFP as well as investigating additional resource options to meet customer needs should the RFP be insufficient to fill all capacity needs.
4. Received certification approval for Plant Yates Units 8-10 on August 29, 2024, with monthly status reports to the Commission starting in September 2024, and the first semi-annual Yates Construction Monitoring Report to be filed in February 2025.
5. Continued to assist customers with evaluating participation in the DER Colocation ("DCL") and DER Customer-Owned ("DCO") Programs. The Company has fielded interest and engaged with multiple customers on specific site and resource discussions. Program modifications have been included in this filing to provide additional value for participants and non-participants with a goal of increasing participation.
6. Developed materials, tools, and contracts for the Curtailable Load ("CL") Program, which opened for enrollment on January 1, 2025. Continued to assist customers with evaluating a portfolio of options available to customers with co-located assets or flexible loads.
7. Provided MARTA and Walmart revised drafts of the DCL Program and DCO Program tariffs and worked with MARTA and Walmart to address questions related to the tariffs.
8. Expanded enrollment in the Residential Thermostat Demand Response ("DR") Program to more than 38,000 customers and further evaluated program potential.

9. Evaluated and developed a residential and small commercial solar and battery pilot program (included in this filing) that incorporates feedback from Staff and interested parties. See Chapter 10 for additional information regarding the Solar Plus Storage Pilot Program.
10. Developed transmission projects necessary to accommodate the loads and resource portfolio approved in the 2023 IRP Update as described in the 2024 GA ITS Ten-Year Plan.
11. Researched funding opportunities for DSM, DERs, and energy storage systems available under the Inflation Reduction Act ("IRA").
12. Collaboratively engaged with the Clean Energy Buyers Association ("CEBA") regarding the development of a carbon-free energy customer program. The engagement with CEBA is included in the proposed changes to the CARES subscription program set forth in this filing which includes the ability for Georgia Power to procure energy from customer-identified resources.
13. Held two meetings with Advanced Power Alliance ("APA") and Southern Renewable Energy Association ("SREA") that addressed topics related to the Transmission Planning process.

2.2 – 2022 IRP

The Commission approved Georgia Power's 2022 IRP, with modifications specified in the Order Adopting Stipulation dated July 29, 2022, in Docket No. 44160 (the "2022 IRP Order"). Consistent with the 2022 IRP Order and the Company's 2022 IRP Action Plan, Georgia Power has taken or will take the following actions:

1. Retired Plant Wansley Units 1-2 and 5A and Plant Boulevard Unit 1 on August 31, 2022.
2. Filed Unit Retirement Study results,[8] including Plant Bowen Units 1-2, in this 2025 IRP. Additional information is found in Section 8.2 and in Technical Appendix Volume 1.
3. Proceeded with effluent limitation guidelines ("ELG") compliance activities at Plant Bowen and Plant Scherer. The Company is on track to meet the National Pollutant Discharge Elimination System ("NPDES") permit compliance date of December 31, 2025, for Plant Bowen, and the Voluntary Incentives Program ("VIP") regulatory deadline of December 31, 2028, for Plant Scherer. Additional environmental compliance activities are detailed in Chapter 9 and Technical Appendix Volume 1.
4. Submitted annual ECS filings with the Commission on March 31, 2023, and April 1, 2024. Submitted CCR ARO filings with the Commission on March 31, 2023, October 1, 2023, April 1, 2024, and October 1, 2024. Additional information on the Company's ECS and CCR activities are provided in Chapter 9, Technical Appendix Volume 1, and Selected Supporting Information in Technical Appendix Volume 2.
5. Filed the CCR Report on Outcome of Beneficial Use RFP with the Commission on September 15, 2023.

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[8] As requested in this 2025 IRP, the Company is not pursuing retirement of Plant Gaston Units 1-4 and A and Plant Scherer Unit 3 by December 31, 2028. Additional information regarding this request is found in Section 8.2.

6. Developed and initiated the transmission projects necessary to accommodate the unit retirements approved in the 2022 IRP. Additional information is provided in Chapter 11 and Technical Appendix Volume 3.
7. Developed and filed annual transmission update reports on February 28, 2023, and February 29, 2024. Met with Commission Staff on March 23, 2023, and March 28, 2024, regarding these reports.
8. Met with Commission Staff on June 22, 2023, March 28, 2024, and October 28, 2024, regarding the 2022 IRP North Georgia Reliability & Resilience Action Plan and updates on strategic transmission projects developed by the ITS Participants to allow for future retirements of existing coal resources and the continued development of renewable resources in Georgia. Additional information is provided in Chapter 11 and Technical Appendix Volume 3.
9. Received certification from the Commission for the six long-term PPAs for capacity and energy from Plant Wansley Unit 7; Plant Dahlberg Units 2 and 6; Plant Harris Unit 2; Plant Dahlberg Units 1, 3, and 5; Plant Monroe Units 1-2; and Plant Dahlberg Units 8-10. Received authorization from the Federal Energy Regulatory Commission (“FERC”) for affiliate transactions associated with the Southern Power PPAs.
10. Filed the Engineering, Procurement, and Construction (“EPC”) agreement with the Commission on August 9, 2024, for the McGrau Ford Phase I BESS, which was approved on December 12, 2024.
11. Issued the All-Source Capacity RFP for 2029-2031 on June 20, 2024, and initiated evaluation of submissions. The Company is actively evaluating the results of this All-Source RFP as well as investigating additional resource options to meet customer needs should the RFP be insufficient to fill all capacity needs. The Company expects to submit a certification application for the winning submissions in July 2025, with an order expected from the Commission by November 2025.
12. Issued the CARES 2023 US RFP for Renewable Generation on December 22, 2023. Determination of the Short List is slated to be announced in Q1 2025. The Company expects to issue the CARES 2025 US RFP for Renewable Generation by June 2025.
13. Issued the 2023 RFP for Solar Photovoltaic Distributed Generation (“2023 DG RFP”) on August 28, 2023. Executed 12 PPAs for a total of approximately 42 MW, each of which were deemed certified by the Commission throughout the fall of 2024.
14. Issued the 2024 RFP for Solar Photovoltaic Distributed Generation (“2024 DG RFP”) on October 8, 2024. The Company expects to submit certification applications for successful bids by September 2025.
15. Issued the 2023 Biomass RFP and received certification of approximately 78 MW of biomass resources on September 20, 2024.
16. The Company expects to issue the 500 MW ESS RFP in Q4 2025 with expected certification from the Commission in Q3 2027.

17. Met with Commission Staff and the Independent Evaluator ("IE") to determine the criteria and methodology for evaluating, ranking, and selecting bids through the best cost methodology, which was subsequently applied to the evaluation of bids received in the CARES Utility Scale RFPs and DG RFPs.
18. Implemented the statewide solar DG Hosting Capacity tool in November 2023. The tool supports the DG RFP process by helping potential bidders locate sites based on the results of feeder studies conducted pursuant to the 2022 IRP Order. The first annual update to the hosting capacity tool was released in December 2024. The Company anticipates semi-annual updates to the tool beginning in 2025.
19. Established the DG Working Group in coordination with Commission Staff in 2022 and complied with all DG Working Group meeting and summary requirements from the 2022 IRP Final Order.
20. Filed quarterly Community Solar Participation Reports with the Commission beginning Q1 2023.
21. Executed contracts with 20 customers to participate in the Flex REC program. The Company has retired 443,148 RECs on their behalf since program commencement.
22. Met with Staff to resolve previously outstanding concerns regarding the RCB Framework and Renewable Integration Study. See Technical Appendix Volume 2 for the updated RCB Framework and Renewable Integration Study.
23. Continued to file semi-annual hydro modernization reports, detailing the Company's progress on its hydroelectric modernization efforts. Submitted cost-benefit analysis for Plant Burton and for the hydro modernization requests in this 2025 IRP. Additional information regarding progress on approved projects is in Section 8.6.
24. Continued to market the 250 MW DER Customer Program Pilot as a resiliency solution alongside the DCL, DCO, and CL Programs approved in the 2023 IRP Update.
25. Initiated the four DER local reliability and constraints ("LRC") pilot projects for Mansfield, Savannah, Moreland Way, and Lake Sinclair feeders. Completed major activities including distribution feeder interconnection studies, defined site requirements, and development of DER plant technical requirements. Potential location options have been identified for the Mansfield and Lake Sinclair pilot projects. Siting efforts for the Savannah and Moreland Way pilot projects are paused until development of the Mansfield and Lake Sinclair pilot projects is complete.
26. Filed Integrated Hydrogen Microgrid reports on August 2, 2024, and November 4, 2024, and will continue to file quarterly reports on project progression consistent with the 2022 IRP Order.
27. Developing the Subsequent License Renewal Application ("SLRA") and Environmental Report ("ER") submittal to U.S. Nuclear Regulatory Commission ("NRC") for the Plant Hatch nuclear units, which is scheduled to be filed by the end of Q3 2025 with the License Extension expected to be approved in Q3 2027. The project is on track of the original baseline schedule and budget.

28. In accordance with the Vogtle Prudence Order, the Company has developed a DSM case proposing a savings target of at least 0.75% of annual retail sales as part of the 2025 IRP and DSM Certification Application.
29. Per the 2022 IRP Order and Commission Staff's decision based on program evaluation findings, the Company paused the Commercial Behavioral program in 2025 pending decertification in 2025 IRP.
30. In accordance with both the 2022 IRP action plan and the 2022 Rate Case Order Adopting Settlement ("2022 Rate Case Order"), the Company has pursued its DERMS solution and related technologies. The Company's DERMS request for information ("RFI") was completed in 2023, followed by a DERMS RFP that was completed in 2024. Additional details are provided in Section 10.4.

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Chapter 3. Integrated Resource Planning

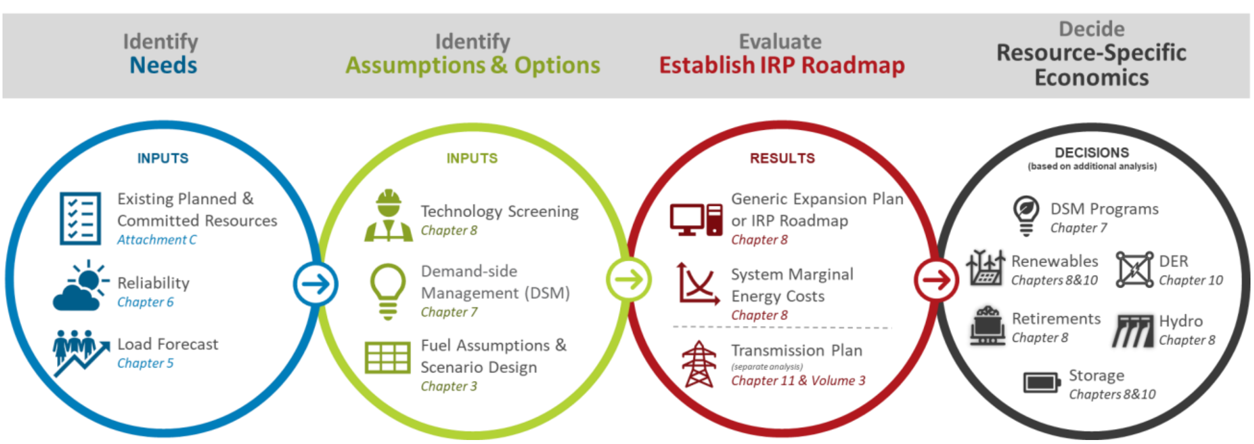
The development of Georgia Power's triennial IRP is part of a continuous planning process involving many diverse disciplines and areas of expertise from Georgia Power and Southern Company Services ("SCS"). This process provides for a structured, robust, and well-reasoned framework through which both demand-side and supply-side resources are equitably evaluated to develop a plan that provides for reliable and economical electric energy to serve customers' energy needs.

3.1 – IRP Process

The IRP process includes sequential planning steps used to determine resource needs, produce generic expansion plans, and develop System marginal energy cost forecasts that inform resource planning decisions. When developing the IRP, the Company begins by establishing reliability criteria while assessing the System's overall reliability needs. During this step, the Company establishes seasonal target reserve margins that define the appropriate level of reliability for the System. This step also considers the potential reliability contribution of new resource additions while routinely seeking to proactively identify potential evolutions in System reliability needs. The Company then applies these reliability criteria to the demand and energy forecasts to determine the amount and type of capacity that is required to reliably meet forecasted capacity needs. The amount of capacity required is compared to existing, planned, and committed resources. This comparison results in a needs determination, which establishes the amount and timing of capacity needs. Following these steps, the Company completes an expansion planning analysis that determines the optimal least-cost resource mix, or generic expansion plan. This analysis provides a roadmap of potential options to meet future needs. Using the generic expansion plan, more detailed production cost modeling is conducted to produce hourly forecasted marginal energy costs.

Using this information, the Company then performs resource-specific economic evaluations for both demand-side and supply-side options. If a need is identified in the timeframe required to plan and build the longest lead time resource, then a separate generation selection is performed. Once resource decisions are made, those decisions then become inputs that inform subsequent IRP processes. An overview of the process by which the IRP is developed is shown in Figure 3.1.

Figure 3.1: IRP Process



Because the future is inherently uncertain, numerous scenarios with varying planning assumptions are developed to inform the Company's resource planning decisions. The steps of the IRP process described above are then conducted for each of the scenarios to produce a range of well-rounded results that facilitate the determination of the most appropriate solutions. This process is described in more detail throughout the 2025 IRP and its Technical Appendices and results in a resource plan that incorporates demand-side and supply-side options to serve customers in a reliable and economical manner that appropriately accounts for flexibility and risk. The Company's base case is established using a planning scenario that includes the 111 GHG Rules.

3.2 – Scenario Development Overview

Many factors affecting resource planning involve future uncertainties. Thus, the Company creates scenarios to help understand these future uncertainties, which allows it to make appropriate planning decisions. Key uncertainties affecting planning include (1) future pressure on 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. To construct its planning scenarios, the Company identifies different reasonably plausible views of the future that are meaningfully different from one another in each of these four areas. These views are then combined to create several scenarios. For each scenario, the Company uses its modeling system, Aurora, to identify a least-cost expansion plan that reliably meets load and satisfies many other conditions. The views and scenarios are refreshed annually. For Budget 2025[9] ("B2025") the Company created nine scenarios.

As it relates to pressure on CO_2 emissions, in the spring of 2024, the Environmental Protection Agency ("EPA") finalized the 111 GHG Rules. See Chapter 9 for more details on these rules. Because the ultimate outcome of the 111 GHG Rules is subject to legal uncertainty due to ongoing petitions for review, the Company's planning scenarios consider both the possibility that the rules remain in effect and the possibility that they do not.

The Company annually refreshes the set of planning scenarios it uses for conducting resource analyses. Each year, the Company considers updates based on multiple factors, including changes in regulation and legislation, technological developments, revised economic projections and communication with current and potential customers, and revised fuel market conditions. In constructing its scenario framework, the Company aims for a design in which individual scenarios are meaningfully different from one another. Conducting analyses using scenarios that are not meaningfully different from one another does not add to the useful information provided by the overall analysis and can distort conclusions by over-representing similar assumptions in the analysis.

The Company reviewed and updated its views of future GHG pressure, future technology cost and performance, future load growth and future fuel prices and created nine scenarios to support its expansion planning included in support of the 2025 IRP. The B2025 scenarios are identified below.

[9] The analyses are conducted during calendar year 2024 for use during calendar year 2025.

3.3 – B2025 Scenarios

The Company considers multiple views of future pressure on the Company's CO_2 emissions, including the 111 GHG Rules, multiple views of future cost and performance of generating technologies, multiple views of future electricity consumption, and multiple views of the future price of fuels, especially natural gas. For B2025, the Company assembled multiple views in these four areas into nine distinct planning scenarios, which are summarized in Table 3.3. For example, as shown in Table 3.3, Scenario 1 (111-MG0) is defined by pressure on CO_2 emissions consistent with the 111 GHG Rules, includes the *Tech Portfolio* view of future cost and performance of technologies, the *Standard* load forecast view, and the *Moderate* view of future fuel prices.

Table 3.3: B2025 Scenario Design

Scenario	GHG pressure view	Tech view	Load view	Fuel view	Label
1	111	Tech Portfolio	Standard	Moderate	111-MG0
2	111	Tech Portfolio	Standard w/ HG0 delta	Higher	111-HG0
3	111 + Higher	IRA 2035	Standard	Moderate	111-MG50
4	Lower	Tech Portfolio	Standard	Lower	LG0
5	Lower	Tech Portfolio	Standard	Moderate	MG0
6	Lower	Tech Portfolio	Standard w/ HG0 delta	Higher	HG0
7	Moderate	IRA 2045	Standard	Moderate	MG20
8	Higher	IRA 2035	Standard	Moderate	MG50
9	Emissions Limit	IRA 2045	Standard	Moderate	EL

The description of the assumptions and details of these different views are provided in the Scenario Views section below.

The B2025 scenario design recognizes future pressure on CO_2 emissions as a key driver of the Company's long-term planning. In constructing each scenario, views in each of the other areas—technology, load, and fuels—were assembled to be consistent with the view of GHG pressure in the scenario. For example, the technology view is designed so that availability of IRA tax credits is assumed to continue until the end of the modeling horizon in scenarios with the *111* or *Lower* views of future GHG pressure and to end earlier otherwise. In the Tech Portfolio view the IRA tax credits are assumed to be available throughout the modeling horizon. In Table 3.3, "IRA 20xx" indicates the last begin-construction year assumed for the IRA tax credit availability.

The B2025 scenario design reflects an appropriately diverse set of plausible, meaningfully different views of the future evolution of the key resource planning drivers.

3.4 – Scenario Views

As shown in Table 3.3, the Company divided its scenarios into two sets. The first set adopts the view that the recently finalized rules associated with GHG emissions under sections 111(b) and 111(d) of the Clean Air Act remain in effect. There are three scenarios in this set. The other set of scenarios adopts the view that the 111 GHG Rules do not remain in effect. There are six scenarios in this set. All nine scenarios differ from one another by adopting different combinations of views in four key areas: the future degree of GHG pressure; the future cost and performance of generating and storage technologies; future load growth; and future price of fuels. The description and details of each of these four key areas are discussed in the following sections.

3.4.1 – Greenhouse Gas Pressure

The degree of pressure on GHG emissions in the future is uncertain.[10] The Company considered six different views of how GHG pressure could evolve. The first view is that GHG pressure remains unchanged from where it is today (*111* view). The second view is that in addition to the 111 GHG Rules remaining in place, a higher degree of GHG pressure is exerted on the Company's emissions (*111 + Higher* view). The third view is that the 111 GHG Rules requirements do not remain in place, and no additional pressure takes their place (*Lower* view). The fourth view is that the 111 GHG Rules do not remain in place, and a moderate degree of GHG pressure is exerted on the Company's emissions (*Moderate* view). The fifth view is that the 111 GHG Rules do not remain in place, and a higher degree of GHG pressure is exerted on the Company's emissions (*Higher* view). Finally, the sixth view is that a limit is placed on the Company's aggregate emissions (*Emissions Limit* view). These views have been chosen to span a range of currently plausible outcomes.

Under EPA's 111 GHG Rules, beginning January 1, 2032, new natural gas combined cycle ("NGCC") units must either capture and sequester at least 90% of their GHG emissions or operate with an annual average capacity factor of 40% or less. Existing coal units have three options: (1) retire by January 1, 2032; (2) capture and sequester 90% of their GHG emissions beginning January 1, 2032; or (3) generate at least 40% of their energy using natural gas beginning January 1, 2030, and retire by January 1, 2039. The Company's *111* view requires compliance with the provisions of these rules.

In addition to the 111 GHG Rule requirements, the Company's *111 + Higher* view of future GHG pressure imposes a higher degree of CO_2 pressure in the form of a fee on GHG emission from the Company's facilities. The fee begins in 2035 at $50 (2023$) per metric ton of CO_2 and rises at 7% above inflation through the modeling horizon. The fee is a proxy for various forms of pressure including regulatory or legislative policy, or pressure from customers or investors.

In the Company's *Lower* view, the 111 GHG Rules do not remain in effect. The *Lower* view assumes no fee on CO_2 emissions but does require carbon capture at all new NGCC units that become operational in 2040 and after. The assumed carbon capture requirement date reflects uncertainty in the legal outcome of the existing rules, as well as the pace of technology advancement, but considers that EPA is required to review and potentially update the GHG emission standards on a regular basis.

[10] As referred to herein, carbon pressure, CO_2 pressure, and GHG pressure are all used to reflect carbon-based emissions and pressure to reduce those emissions whether through taxes, penalties, or other restrictions.

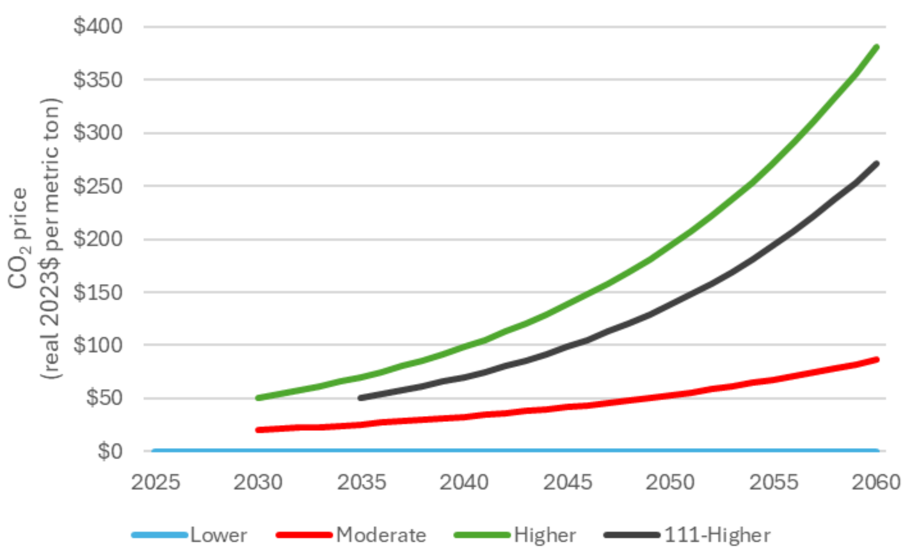
The Company's *Moderate* view adds to the *Lower* view a fee on CO_2 emissions that begins in 2030 at $20 (2023$) per metric ton of CO_2 and grows at 5% above inflation through the modeling horizon. This fee is a proxy for various forms of pressure on the Company's GHG emissions, including regulatory or legislative policy, or pressure from customers or investors. The assumed 2030 start year is consistent with a projected compliance horizon for future regulation or legislation. In this view it is also assumed that carbon capture is required at all new NGCC units beginning in 2037. These dates are uncertain but reflect potential outcomes from future policies and/or reviews required under the Clean Air Act.

The Company's *Higher* view builds on the requirements of the *Lower* and *Moderate* views and adopts a fee on CO_2 emissions that begins in 2030 at $50 (2023$) per metric ton of CO_2 that grows at 7% above inflation through the modeling horizon. The assumed 2030 start year is consistent with a projected compliance horizon for future regulation or legislation and assumes carbon capture is required at all new gas CC units beginning in 2037.

The Company's CO_2 *Emissions Limit* view imposes a requirement that the Company's annual aggregate CO_2 emissions fall to 10% of current levels by 2050. (Relative to 2007 emissions, this is a 95% reduction.) This view is implemented in the Company's Aurora expansion plan modeling with a CO_2 price trajectory.

The price paths views are illustrated in Figure 3.4A.

Figure 3.4A: Views of future price pressure on CO_2 emissions



3.4.2 – Technology Cost and Performance

Electricity generating technology is always evolving, and there are numerous resources that can contribute to meeting the demand for electricity. The pace and direction of the evolution of each of these resources is uncertain. The Company maintains a technology screening process that evaluates a wide portfolio of technologies at varying levels of development for inclusion in its planning scenarios. This screening process characterizes technologies that are currently commercially available as well as those that are expected to be commercially available at some point during the IRP's 20-year planning horizon.

Currently available commercial technologies included in the Company's planning scenarios are deployed, tested, and monitored to such a degree as to be considered generic and repeatable. The pre-commercial technologies included in the Company's planning scenarios are at various stages of their developmental processes. The Company bases its assessment of these technologies on engagement with a variety of manufacturers, labs, and other organizations. The Company develops representative cost and performance information for technologies that are expected to become commercially available during the planning horizon. Since the pre-commercial technology portfolio represents estimates of cost and performance for technologies in development, the Company has less confidence in its cost and performance estimates for these technologies than the resource technologies included in the commercial portfolio. The Company is including these technologies in its planning analyses even though they are not yet commercially available.

For the B2025 IRP analyses the technologies that passed initial screening, indicating their potential cost-effectiveness, include NGCC, dual-fuel CT with selective catalytic reduction ("SCR") (oil-fueled in winter, natural gas otherwise), solar photovoltaic ("PV"), wind, nuclear (AP-1000), lithium-ion battery storage, and compressed air or pumped thermal energy storage. In addition, NGCC with CCS also passed initial screening based on an assumed trajectory of technology and infrastructure development towards future commercial availability. While this trajectory and ultimate costs remain highly uncertain, the inclusion of NGCC with CCS allows the Company to evaluate scenarios for this potential future resource option. Please see Chapter 8 and the Resource Mix Study in Technical Appendix Volume 2 for more information on technology screening and candidate expansion planning units.

The net cost to customers of some resources can be significantly affected by applicable tax credits. The IRA includes numerous tax-crediting provisions that significantly reduce the net cost to customers of technologies that emit low or no CO_2, including solar, wind, storage, nuclear, and gas with CCS. Many of these provisions end at the later of two dates—the year 2032 or the year in which total CO_2 emissions from electricity production in the U.S. decline to 25% of the 2022 total. As the latter year is unknown and impactful, the Company considers three different views of it. In the Company's *Tech Portfolio* view of future technology cost and performance, the IRA clean electricity production tax credits ("PTC") and investment tax credits ("ITC") are assumed to last for the duration of the modeling horizon. In the Company's *IRA 2045* view, these tax credits are assumed to phase out in 2045. In the Company's *IRA 2035* view, these tax credits are assumed to phase out in 2035. Analysis by the U.S. Energy Information Administration ("EIA") suggests that absent additional pressure on CO_2 emissions, the IRA tax credits alone are not sufficient to drive total U.S. electricity CO_2 emissions down to 25% of 2022 levels through the modeling horizon. In its scenario analysis, the Company adopts this view in scenarios that have *Lower* pressure on future CO_2 emissions. In the scenarios with *Moderate* or *Emissions Limit* pressure on future CO_2 emissions, the Company adopts the view that the IRA tax credits will phase out in 2045. In scenarios with *Higher* pressure on future CO_2 emissions, the Company adopts the view that the IRA tax credits will phase out in 2035.

3.4.3 – Load Growth

To assess future electricity consumption, the Company considers two different views of future load growth in its planning scenarios. One is a *Standard* view and the other is a view consistent with lower loads due to higher future natural gas prices (*Standard w/ HG0 Delta*). Additional load views are considered in the B2025 Load & Energy Forecast in Technical Appendix Volume 1 and in the Financial Review in Technical Appendix Volume 2.

- Standard. The Company updates annually its forecast of electricity consumption through the planning horizon. The load forecast is prepared separately for each of the three types of customers (i.e., residential, commercial, and industrial) for each of the three retail operating companies and is aggregated into a System total for expansion planning modeling. This view of future load growth is used in most scenarios. This view includes significant growth of electricity consumption associated with commercial and industrial customers expected to initiate or expand operations as Company customers. At present, the Company sees this significant growth occurring through the mid-2030s.
- Standard w/ HG0 Delta. The *Standard w/ HG0 Delta* view recognizes the relationship between the future consumption of electricity and the future price of natural gas. This relationship is not straightforward because natural gas is both an input to electricity production and a substitute for electricity in some end uses. Thus, the Company has developed a load growth adjustment used in the scenario with higher future prices of natural gas. This load growth adjustment is derived from analyses done by the U.S. EIA for its Annual Energy Outlook ("AEO"). The AEO identifies a lower electricity consumption path associated with higher future natural gas prices, reflecting the important feedback in the relationship between future natural gas prices and future load growth.

  For the B2025 planning process, the Company compared southeast U.S. electricity load growth in the AEO 2023 case with a higher future price of natural gas to southeast U.S. electricity load growth in the AEO 2023 Reference case. This difference was smoothed and then used as an adjustment to the Company's Standard load growth view.

These two different views of future load growth are illustrated in Figures 3.4B-3.4D. They show forecasts of weather-normal annual system winter peak load, annual system summer peak load, and annual total system energy.

Figure 3.4B: System Winter Peak Load

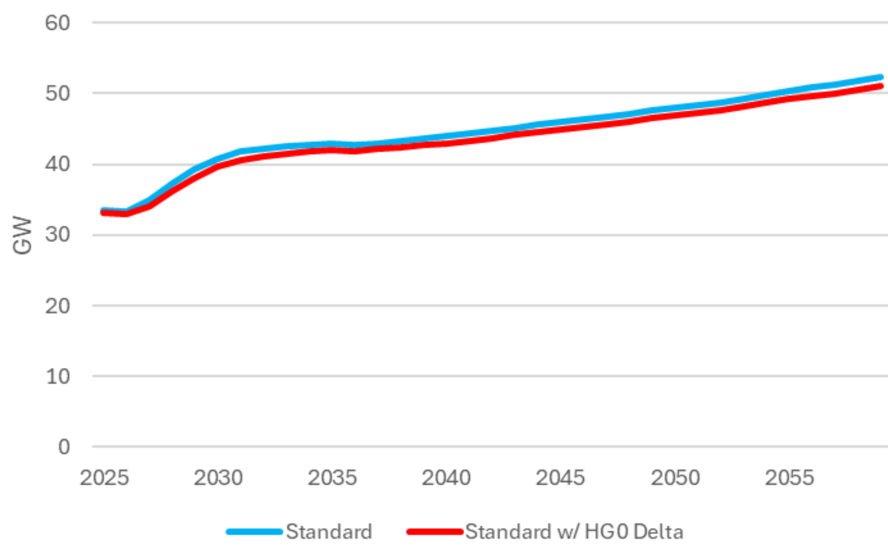


Figure 3.4C: System Summer Peak Load

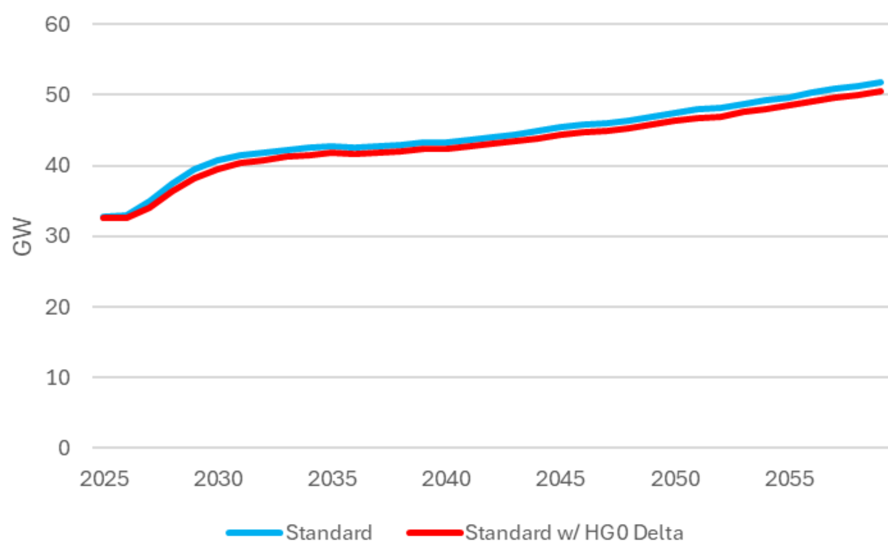
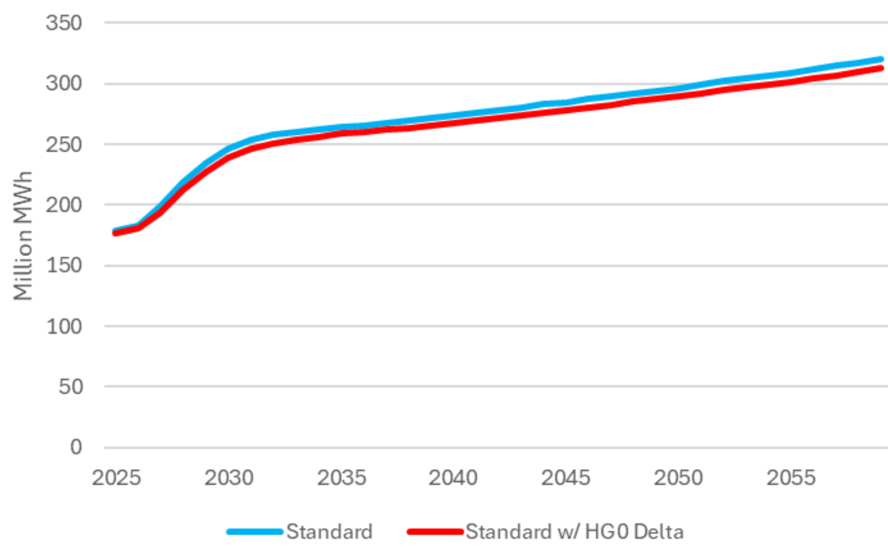


Figure 3.4D: Annual Total System Energy



3.4.4 – Fuel Prices

The future price of fuel is unknown. For the B2025 planning process, the Company considered three different views of how the long-term price of fuels could evolve: a *Lower* price path; a *Moderate* price path; and a *Higher* price path. For B2025, the Company adopted paths produced by the U.S. EIA in its 2023 AEO as its source for future prices of natural gas, coal, and oil. EIA did not produce a 2024 AEO, so the 2023 AEO is EIA's current view.

The AEO is a major annual product of the EIA and is publicly available on the EIA's website (https://www.eia.gov). The analysis supporting the AEO uses the National Energy Modeling System ("NEMS"), EIA's main modeling system of the U.S. energy economy, and is detailed and comprehensive. Full documentation of NEMS can be found on the EIA's website at https://www.eia.gov/outlooks/aeo/nems/documentation. In addition to producing the AEO, EIA uses NEMS to analyze the energy content of policy proposals as requested by Congress or the Administration.

EIA constructs several scenarios each year. For each scenario, NEMS is used to identify price paths for natural gas, coal, oil, gasoline, and many other goods and services, which are consistent with market conditions across the U.S. energy economy in that scenario. All key assumptions and results from the NEMS analysis for the AEO are publicly available for viewing and downloading at no charge on EIA's website. The AEO is highly regarded, readily available, and often used as a reference in conversations about the future of energy in the U.S.

In addition to providing thorough documentation, EIA invites utility participation in workshops at which EIA personnel discuss model issues and assumptions and solicit input for changes. Company personnel participate in these workshops as well as interact with EIA personnel as part of the Stanford Energy Modeling Forum and other venues. Through the years, the Company has developed a solid relationship with key data, analyses, and analytical personnel at EIA, facilitating greater understanding of what is included in the price projections that the Company adopts.

The Company also maintains familiarity with other sources of future fuel price estimates and the key assumptions behind those estimates. These other sources of information are used to help the Company understand the views of others and how they compare to the views adopted by EIA in producing the AEO.

3.4.5 – Long-Term Future Natural Gas Prices

For B2025, the three different views of long-term future natural gas prices that the Company adopted are:

- *Lower* price view: AEO's High Oil and Gas Supply case
- *Moderate* price view: AEO's Reference case
- *Higher* price view: AEO's Low Oil and Gas Supply case

Estimates of technically recoverable tight/shale oil and natural gas resources are particularly uncertain and change over time as new information is gained through drilling, production, and technology development. AEO's "High Oil and Gas Supply" and "Low Oil and Gas Supply" views appropriately reflect this uncertainty.

In AEO's Low Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% lower than in the Reference case for tight oil, tight gas, shale gas in the U.S., for undiscovered resources in Alaska, and for production offshore of the Lower 48 states. Rates of technological improvement that reduce costs and increase productivity in the U.S. are also 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the U.S.

In AEO's High Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% higher than in the Reference case for tight oil, tight gas, shale gas in the U.S. for undiscovered resources in Alaska, and for production offshore of the Lower 48 states. Rates of technological improvement that reduce costs and increase productivity in the U.S. are also 50% higher than in the Reference case. These assumptions decrease the per-unit cost of crude oil and natural gas development in the U.S. In addition, tight oil and shale gas resources are added to reflect new prospects or the expansion of known prospects. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case.

Some of the key drivers of the AEO change from year to year reflect the evolution of important information about the U.S. energy economy. As an example of some of these changes, Table 3.4 provides some of the key assumption changes from AEO 2022 to AEO 2023.

Table 3.4: Key Natural Gas Values for AEO 2023 Reference Case

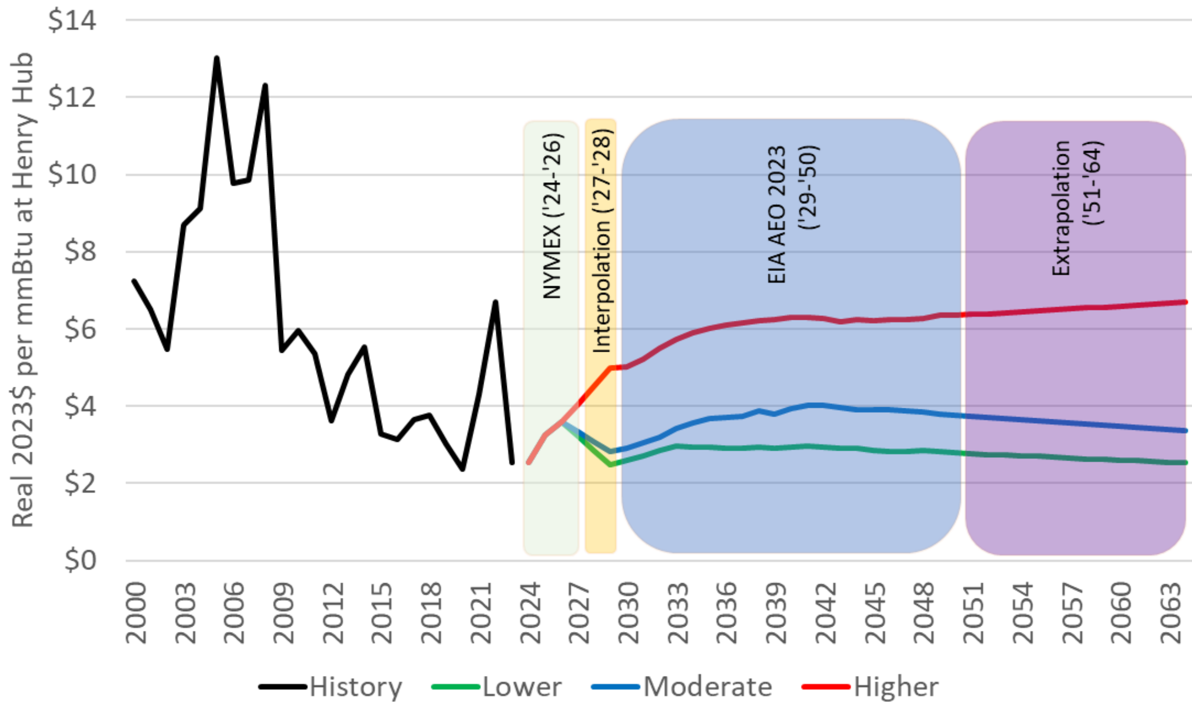
Driver	Key Values for AEO 2023 Reference Case
Resource Size	• 445.3 Tcf in proved shale reserves (20.1 Tcf decrease from AEO 2022) • 2,973 Tcf in total technically recoverable (TTR) U.S. dry natural gas resources (1.6% growth from AEO 2022 to AEO 2023)
Technological Improvement	• Drilling costs fall by 1%/yr • Equipment costs fall by 0.5%/yr • Well productivity increase up to 4%/ yr

3.4.6 – Short-Term Future Natural Gas Prices and Prices Beyond 2050

The Company adopts average closing prices on the New York Mercantile Exchange ("NYMEX") of natural gas contracts for future delivery as its short-term natural gas price forecast. For the analyses supporting this IRP, this applied to prices for the remainder of 2024, for 2025, and for 2026. The Company adopts only one short-term view of future natural gas prices.

As described above, the Company adopts the three different AEO projections described above for 2029 and beyond. The values for 2027 and 2028 are a linear interpolation between the 2026 and 2029 values. The AEO provides price paths through 2050. Beyond 2050, the Company extrapolates the price path from its slope for its last 10 years, as illustrated in Figure 3.4E.

Figure 3.4E: Views of future price of Natural Gas at Henry Hub



3.4.7 – Future Coal and Oil Prices

The future price of coal and oil is also uncertain. For B2025, the Company has adopted three different views of future coal prices and three different views of future oil prices. These views are the coal and oil price paths from the AEO 2023 Reference, High Oil and Gas Supply, and Low Oil and Gas Supply cases. These price paths are illustrated in Figures 3.4F-3.4I.

The relationship between the future price of coal and the future supply of oil and gas is not straightforward. In general, coal and natural gas are substitutes for each other, so when the price of gas is higher, the quantity of coal demanded, and thus its equilibrium price, is higher. Because the overall growth of the U.S. economy can be sensitive to the price of oil and natural gas, however, lower future prices of natural gas can increase overall economic growth enough to increase the price of coal too. These competing effects can be seen in the coal price diagrams that follow. The AEO does not consider cases that directly involve higher or lower views of the future price of coal.

Figure 3.4F: Views of future price of coal at mine, by scenario, Central Appalachia: Medium Sulfur Bituminous

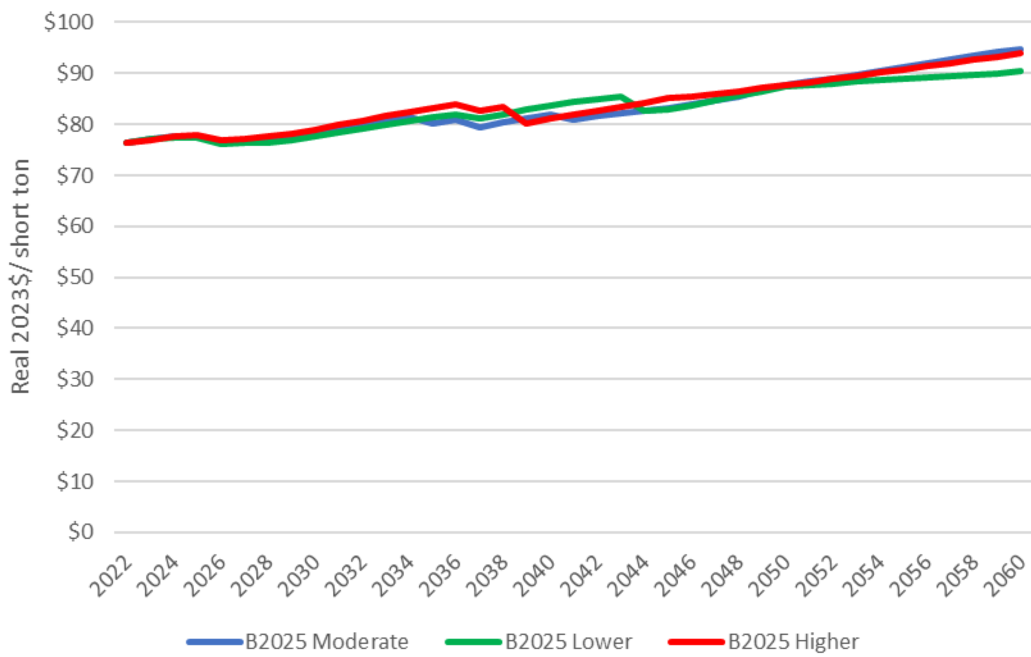


Figure 3.4G: Views of future price of coal at mine, by scenario, Illinois Basin

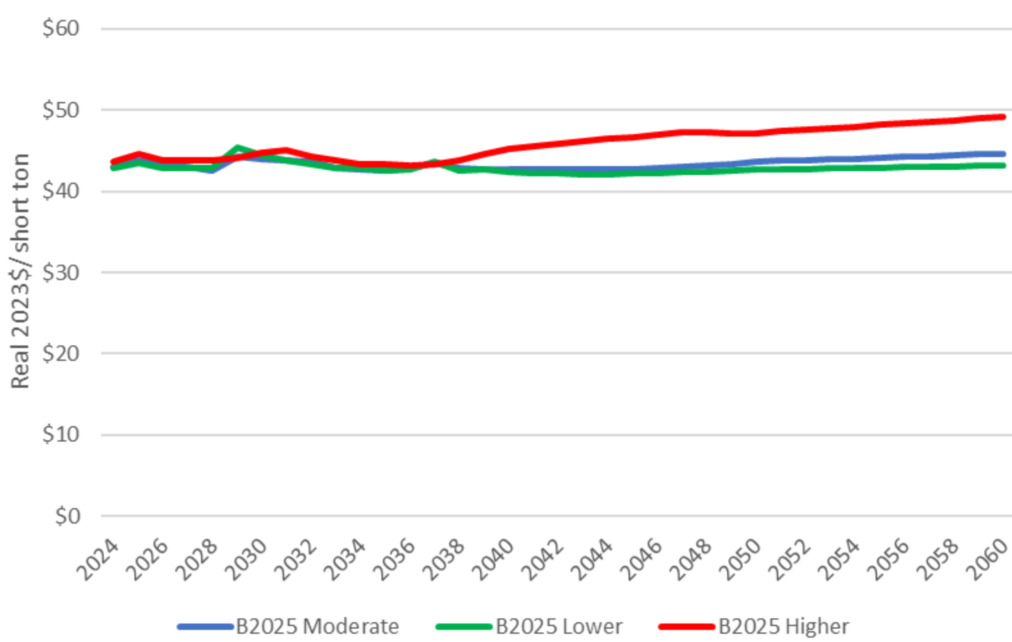


Figure 3.4H: Views of future price of coal at mine, by scenario, Powder River Basin

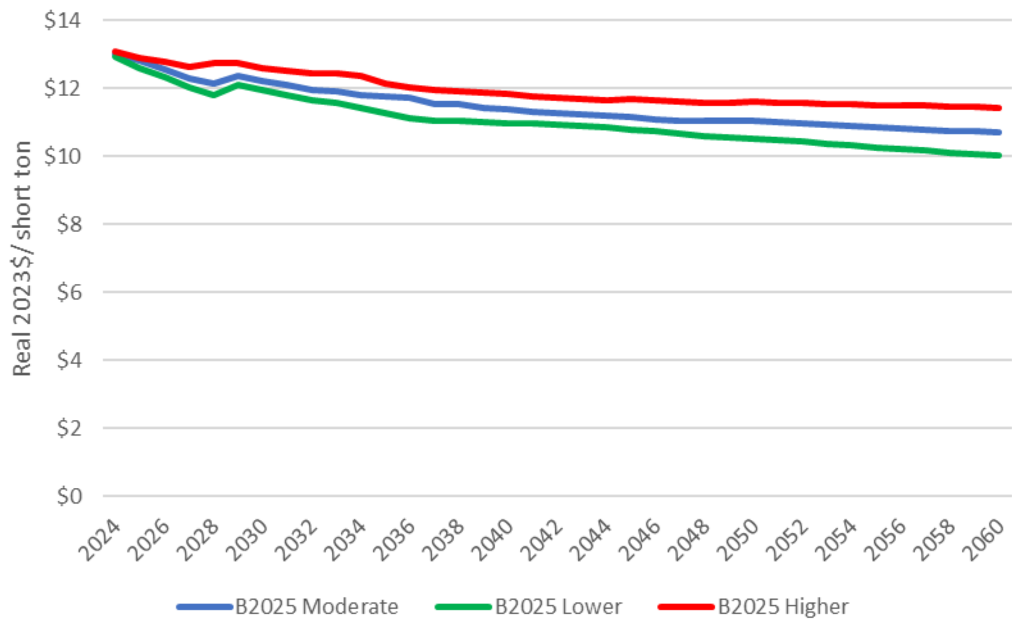
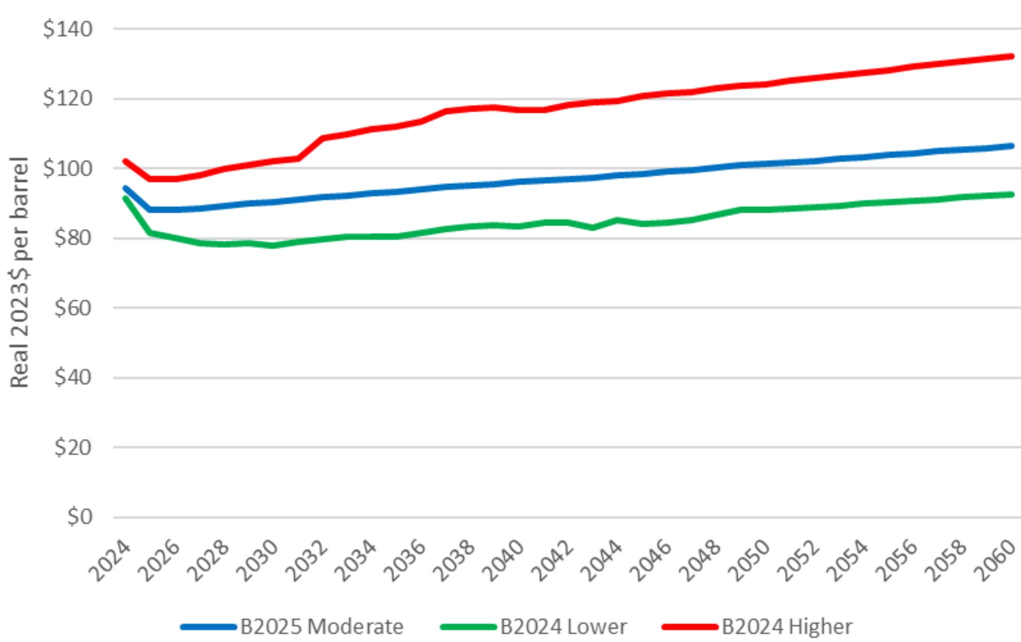


Figure 3.4I: Views of future price of oil, West Texas Intermediate



3.5 – Conclusion

The scenario planning process provides a framework for understanding and considering the impact of key uncertainties in resource planning, and in so doing, aids the Company in making appropriate resource planning decisions when faced with future uncertainties.

Chapter 4. Economic Development

Georgia's state-led, comprehensive, and dynamic economic development strategy provides significant benefits to Georgians, including job creation, business retention, and investments that support the long-term success of Georgia's communities. Georgia Power actively supports Georgia's economic development efforts and believes in the benefits that a growing Georgia provides for all Georgians. Economic development momentum remains strong in Georgia, with approximately $45 billion in capital investment and 65,000 jobs added to the state's economy since the end of Fiscal Year 2022. In September 2024, the state announced another strong year of economic development, with 429 facility expansions and new locations "resulting in more than $20.3 billion in investment, and the commitment of 26,900 new, private sector jobs statewide"[11] between July 1, 2023, and June 30, 2024 ("Fiscal Year 2024").

New and expanding economic development projects in Georgia have progressed more rapidly and on a larger scale than in previous years. Growth in emerging industries such as electric transportation ("ET"), data centers, and solar manufacturing have accelerated since 2021. Fiscal Year 2024 saw considerable growth across numerous industries, particularly in energy-intensive manufacturing and technology. "Manufacturing, including the aerospace, automotive, and e-mobility sectors, accounted for over 50% of expansions or new locations in FY2024."[12] By mid-2024, the manufacturing sector led in both investment and job creation in Georgia, representing 53% of job growth and 54% of capital investment in the state.

In February 2024, Georgia achieved its third consecutive record-breaking year for trade exports, "surpassing the previous record by $2.7 billion."[13] This data highlights the rapid and significant economic development taking place in Georgia over the past three years, which is supported by the state's 12 international offices. Much of this growth comes from international companies seeking to do business in Georgia. For example, companies from Korea have significantly bolstered EV and battery investments in the state. Figure 4 depicts economic development trends in job creation and capital investment for Georgia for Fiscal Years[14] 2018 through 2024.

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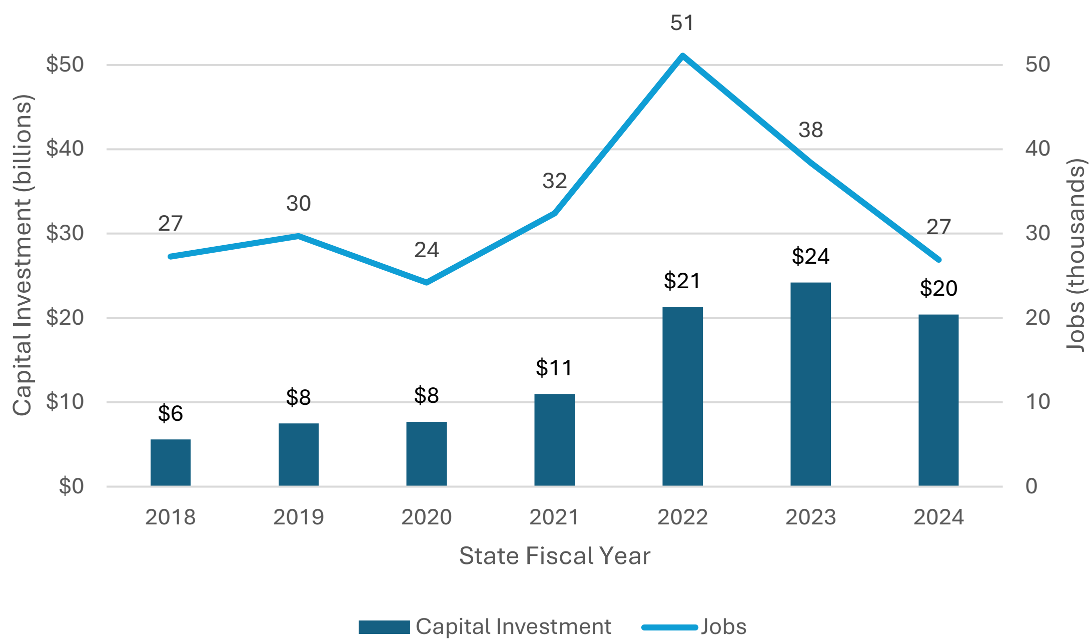
[11] Press Release, Brian P. Kemp, Governor of Georgia, Georgia Job Creation Remains Strong (August 29, 2024), https://georgia.org/press-release/gov-kemp-georgia-job-creation-remains-strong.

[12] *Id.*

[13] Press Release, Georgia Dep't of Econ. Dev., State of Georgia Breaks Export Records for Third Straight Year (February 14, 2024), https://georgia.org/press-release/state-georgia-breaks-export-records-third-straight-year.

[14] The State of Georgia Fiscal Year represents July of the prior year through June of the stated year.

Figure 4: Georgia Economic Development Historical Trends[15]



Georgia has consistently been recognized as a top state for business. In September 2024, Area Development magazine named Georgia the Top State for Business for the eleventh consecutive year.[16] The announcement highlighted Georgia's top 10 rankings in each survey category, including workforce availability, cost of doing business, cooperative and responsive state government, energy availability and costs, logistics and infrastructure, and site readiness programs. Most recently, Georgia was named the number one state for Best Business Climate by a survey of site selection experts in Site Selection magazine's January 2025 edition.[17]

Additionally, Business Facilities magazine ranked Georgia as the number one state for EV investments and among the top 10 states for food processing, cybersecurity, aerospace and defense, and Artificial Intelligence ("AI") growth.[18] In July 2024, CNBC rated Georgia as the number one state for infrastructure with an A+ score for roads, bridges, railroads, ports, airports, and utilities.[19]

Throughout its history, Georgia Power has served as a trusted partner in supporting Georgia's economic development efforts. In February 2024, Business Facilities magazine named Georgia

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[15] Capital investment and new jobs provided by Georgia Department of Economic Development in July 2024 and includes entire Fiscal Year 2024.

[16] Press Release, Brian P. Kemp, Governor of Georgia, Gov. Kemp Celebrates Top State for Business Ranking at Workforce Summit (September 13, 2024), https://georgia.org/press-release/gov-kemp-celebrates-top-state-business-ranking-workforce-summit.

[17] Ron Starner, *Site Selectors Survey: Why Site Selectors Love the South*, Site Selection (January 2025) https://siteselection.com/site-selectors-survey-why-site-selectors-love-the-south/?utm_source=InvestorWatch&utm_medium=email&utm_campaign=Editorialllll.

[18] Business Facilities 20th Annual Rankings Report, Business Facilities (August 8, 2024) https://businessfacilities.com/20th-annual-rankings-report-2024-state-rankings/.

[19] CNBC, *Top States for Business – 4. Georgia* (July 11, 2024), https://www.cnbc.com/2024/07/11/top-states-for-business-2024-georgia.html.

Power a Top Utility for Economic Development for the third consecutive year,[20] and in September 2024, Site Selection magazine recognized Georgia Power as a "Top Utility" in economic development for the 26th consecutive year.[21]

Georgia Power works closely with the Georgia Department of Economic Development to support initiatives that benefit Georgia. For example, the Hyundai Motor Group Electric Vehicle ("EV") Metaplant facility in Bryan County, which started operations during the fourth quarter of 2024, is the largest economic development project in Georgia's history. Site Selection magazine included Georgia in its "Top Deals in North America" report for 2023, identifying the Hyundai Motor Group's Bryan County project, which is expected to create 8,100 jobs and generate over $5.5 billion in investment, making it the second-largest project the magazine reported that year.[22] The Hyundai Motor Group/SK Innovation project in Bartow County, which will create 3,500 jobs and result in a $4 billion investment, ranked fifth for 2023. Additionally, Site Selection magazine announced in 2024 the North America Top Deals, including Hyundai Motor Group and its LG Energy Solution Battery JV partnership as the third largest project.[23]

With the Commission's constructive oversight, Georgia Power has consistently provided clean, safe, reliable, and affordable electric service to its customers while working to support economic growth that benefits Georgia. The 2025 IRP proposes a reliable, economical, and diverse resource mix that will ensure Georgia Power can continue to meet the energy needs of its customers and support beneficial economic growth in Georgia.

[20] Business Facilities, 2024 Top Utilities (February 7, 2024), https://businessfacilities.com/2024-top-utilities-for-economic-development/#:~:text=These%20top%20utilities%20play%20a%20key%20role%20in%20state%20and.

[21] Adam Bruns, *2024 Top Utilities in Economic Development*, Site Selection (September 2024), https://archive.siteselection.com/issues/2024/sep/2024-top-utilities-in-economic-development-bonus-content.cfm?utm_source=Sidebar&utm_medium=Web&utm_campaign=Optimize&utm_content=RA.

[22] Adam Bruns, *Top Deals 2023*, Site Selection Magazine (May 2023), https://archive.siteselection.com/issues/2023/may/top-deals-2023.cfm.

[23] Adam Bruns, *Top Deals 2024*, Site Selection Magazine (May 2024), https://archive.siteselection.com/issues/2024/may/top-deals-2024.cfm

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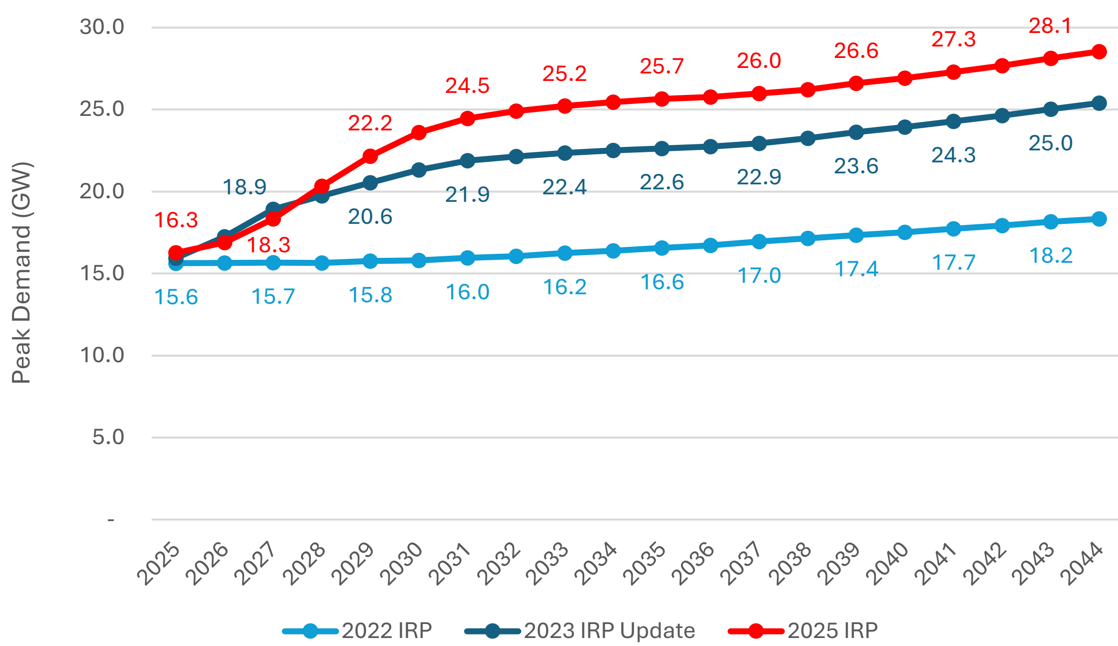
Chapter 5. Load & Energy Forecast

Georgia Power's 2025 IRP load forecast, completed in August 2024, projects continued, extraordinary customer load growth stemming from substantial economic development taking place in Georgia. The demand projected in the 2025 IRP load forecast exceeds the demand projected in both the 2023 IRP Update and the 2022 IRP.[24] At the time of the 2022 IRP, the Company anticipated just over 300 MW of growth between the winter of 2024/2025[25] and the winter of 2030/2031. For this same period, the Company projected approximately 5,900 MW of growth in its 2023 IRP Update, filed in October 2023. Now, in the 2025 IRP, current projections reflect load growth of 8,205 MW through the winter of 2030/2031. This expected load growth reflects a compound annual growth rate of 7% through the winter of 2030/2031. A comparison of projected winter peak demands from the 2022 IRP, the 2023 IRP Update, and the 2025 IRP for the 20-year period spanning the winter of 2024/2025 through the winter of 2043/2044 is provided in Figure 5A below.

Figure 5A: Georgia Power Projected Winter Peak Demand



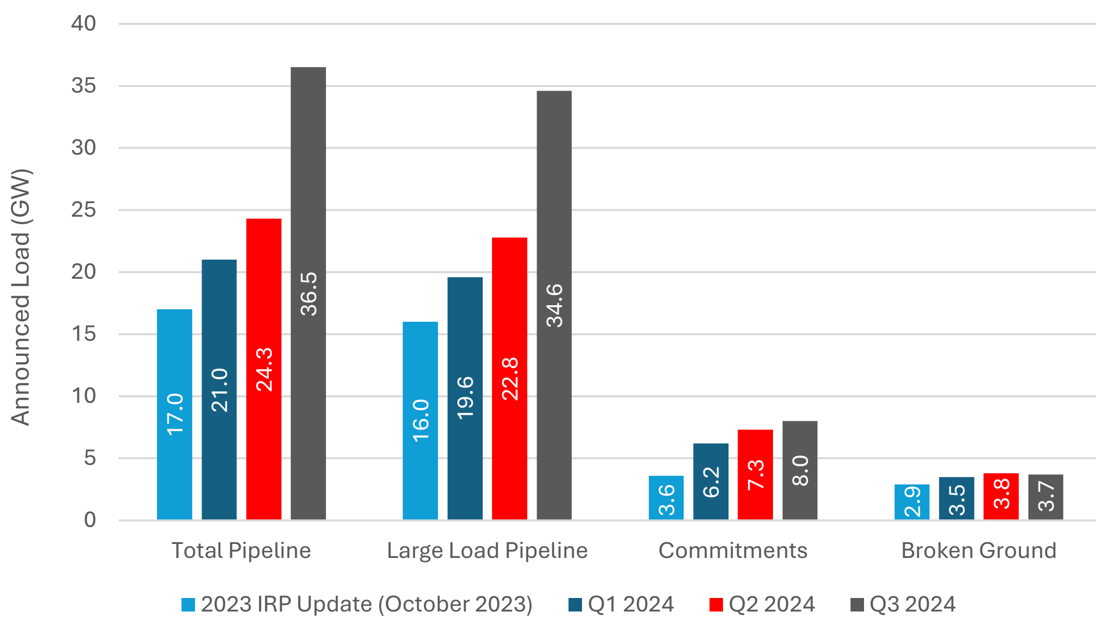
The significant increase in the projected demand for energy since the 2022 IRP reflects the extraordinary growth associated with the numerous new large load[26] projects Georgia Power has been selected to serve as well as a considerable pipeline of potential future projects. The size of

[24] For comparison, the 2023 IRP Update analyzed customer demand starting in the winter of 2023/2024, whereas this 2025 IRP begins its analysis in the winter of 2024/2025.
[25] The Company denotes the winter of 2024/2025 as 2025 and applies this treatment to future seasons and years in Figure 5A. The Company's projected peak winter demand occurs in January of each year.
[26] In general, 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. Note, this is a different threshold than "large load" as used in the Georgia Territorial Electric Service Act O.C.G.A. § 46-3-1 et. al.

many of these projects far exceeds historical annual norms, with some individual projects surpassing 1,000 MW. In addition to the size of the large loads presented by these new projects, many of the projects reflect a higher load factor with around-the-clock operations, which requires a substantial amount of generation and consistent energy delivery throughout the day and night as opposed to only during specific times.

Upon conclusion of the 2023 IRP Update, Georgia Power began filing quarterly large load economic development reports to update the Commission on the large load economic development pipeline identified by the Company. These quarterly reports tracked the total number of both large load customers who have committed to take electric service from Georgia Power and potential large load customers seeking to do business in Georgia.[27] As summarized in Figure 5B, the quarterly reports demonstrate robust growth in the Company's large load economic development pipeline since the 2023 IRP Update.

Figure 5B: Long-Term Pipeline Growth Through the Mid-2030s

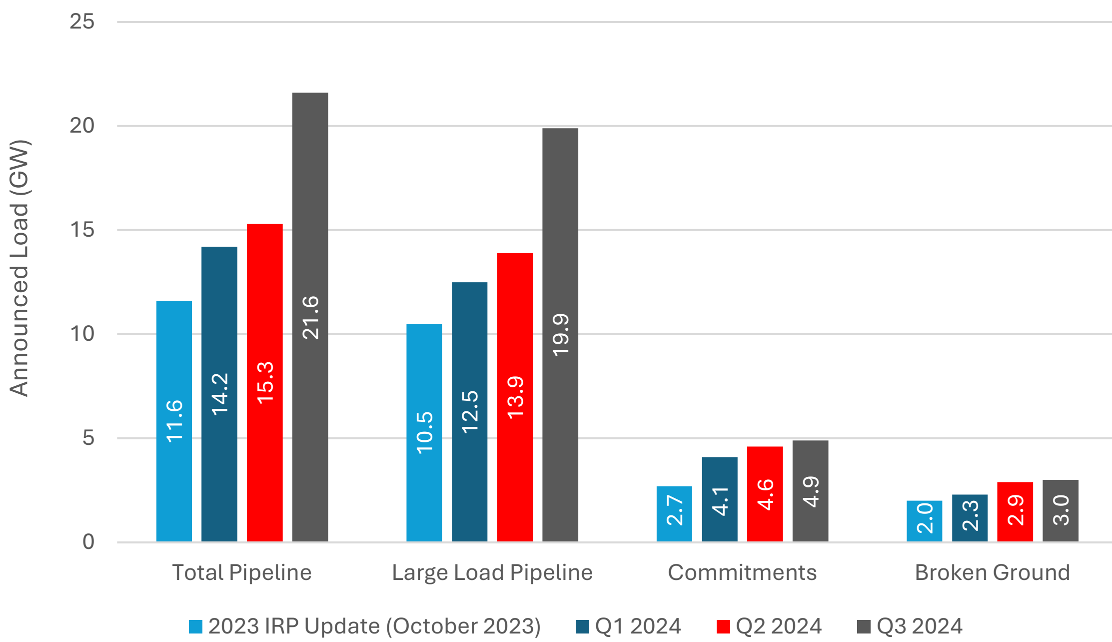


As shown in Figure 5B, and in support of the B2025 load forecast, the long-term[28] large load pipeline grew by approximately 6.8 GW from the 2023 IRP Update filing in October 2023 through June 2024 to 22.8 GW.[29] Over the same eight-month period, the number of large load customers who committed to receive electric service from Georgia Power grew by 10 projects to 7.3 GW, representing an increase of approximately 3.7 GW.

[27] Committed customers are those who have executed a Request for Electric Service from Georgia Power.
[28] As used in reference to the Company's large load customers, long-term captures the time period through the mid-2030s.
[29] The 2025 IRP load forecast is based on data from the Company's large load economic development pipeline as of the end of Q2 2024. As such, facts and figures focus on data through June 2024. To the extent that Q3 2024 data impact potential requests in this 2025 IRP, the Company provides such context in this document. The Company expects to file a report containing Q4 2024 pipeline information in February 2025.

Subsequent to the development of the B2025 Load Forecast, and as shown in the Company's Q3 2024 Large Load Economic Development Report, these committed customers' projects continued to materialize and now represent 8 GW. As depicted in Figure 5C, the Company expects these projects to ramp up significantly in the near-term,[30] as 13 out of 25 large load customer commitments have currently broken ground, representing 3 GW out of 4.9 GW of large load customer commitments through the winter of 2028/2029.

Figure 5C: Near-Term Pipeline Growth Through the Winter of 2028/2029



As a key assumption in its load forecasting process, the Company does not assume or expect all economic development projects (i.e., the large load economic development pipeline) or even the full load of committed projects to materialize. For B2025, the Company continued to risk adjust its organic forecast using the probabilistic model developed in support of the 2023 IRP Update to evaluate the range and likelihood of future potential outcomes of the load growth from new, large load customers. The B2025 Load Forecast is a product of this probabilistic large load growth model combined with the Company's organic residential, commercial, and industrial energy and peak forecasts.

As adjusted, the B2025 Load Forecast accounts for uncertainties related to new large load projects, including state selection, electric provider selection, project delays, and the materialization of load. The Company conducted hundreds of thousands of simulations using different combinations of these uncertainties to produce probability distributions that were then utilized to develop the external adjustments. Additional details regarding the risk adjustment and probabilistic model as well as the full Load and Energy Forecast are contained in the Technical Appendix.

[30] As used in reference to the Company's large load customers, near-term captures the time period through the winter of 2028/2029.

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Chapter 6. Reliability & Resiliency Planning

Prudent utility practice requires that electric utilities maintain sufficient supply-side and demand-side resources to reliably serve the needs of their customers. The ability of supply-side and demand-side resources to meet electrical demand and maintain an appropriate level of System reliability is referred to in the electric utility industry as "Resource Adequacy." The Company establishes the appropriate level of System reliability through its reserve margin study. The Company also undertakes capacity equivalence studies, which ensure that resources that contribute to the Company's Target Reserve Margin are assigned the appropriate capacity value or reliability benefit.

The combination of capacity equivalence valuations and target reserve margins ensures the Company has planned for sufficient capacity to meet peak demands. However, the Company's resource mix continues to be increasingly dependent on energy-limited and intermittent resources. While these changes in the Company's resource mix are expected to provide economic benefits for customers, certain reliability impacts are not fully discernable through traditional reserve margin studies. Therefore, the Company's reliability analysis also examines the changes anticipated in the Company's resource mix due to the continued integration of intermittent resources. The results of this Renewable Integration Study indicate a need for increased levels of operating reserves and/or flexible capacity, as further discussed in this chapter.

6.1 – Reserve Margin Study

Resource Adequacy requires consideration of not only the uncertainties associated with the demand for electricity, but also the uncertainty associated with the reliability of the resources available to meet that demand. The Company's Target Reserve Margin represents the amount of resources needed above forecasted peak demand to meet customer needs notwithstanding these uncertainties. To ensure reliability, the Company must evaluate the required reserve margin using a combination of economic and reliability metrics. As such, a reserve margin study is produced in the year prior to each triennial IRP filing to establish a Target Reserve Margin for the System for both the short-term and the long-term planning horizons. The Company performed such a study in 2024, and a report describing the Company's Reserve Margin Study is included in Technical Appendix Volume 1. The Reserve Margin Study report describes the methodology, metrics, assumptions, and results used to determine the Company's Target Reserve Margin recommendations.

6.1.1 – Seasonal Target Reserve Margins

The use of seasonal planning to provide greater visibility into both summer and winter capacity needs was approved by the Commission in the 2019 IRP Order. In order to effectuate seasonal planning, the Company must also establish seasonal Target Reserve Margins. The Reserve Margin Study evaluated the need for these seasonal Target Reserve Margins. Notably, the results of the most recent Reserve Margin Study continue to reflect the significant presence of winter reliability risks. These risks are associated with 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; (5) increased reliance on natural gas; and (6) market purchase availability. Given the difference in customer load response as well as differences in both the availability and dependability of resources in the summer and winter peak periods, it remains necessary to independently evaluate Resource Adequacy in both the summer and winter peak periods to ensure that System reliability has been appropriately evaluated.

6.1.2 – Defining Target Reserve Margins

The Target Reserve Margin is stated in terms of seasonal weather-normal peak demands and seasonal capacity ratings according to the following formula:

$$TRM_S = \frac{TC_S - PL_S}{PL_S} \times 100\%$$

Where:

TRM_S = Seasonal Target Reserve Margin;

TC_S = Total Seasonal Capacity; and

PL_S = Seasonal Peak Load.

6.1.3 – Target Reserve Margins

To appropriately address seasonal planning needs and winter reliability concerns, the Company will continue to implement seasonal planning as approved in the 2019 IRP Order. After analyzing the load forecast and weather uncertainties, expected unserved energy, as well as projected generation reliability of the System, the Company plans to increase the current 16.25% long-term Summer Target Reserve Margin for the System to 20% as the Summer Target Reserve Margin to be applied to the summer peak planning season. The Company plans to maintain the current 26% long-term Winter Target Reserve Margin for the System as the Winter Target Reserve Margin to be applied to the winter peak planning season.

Two primary evaluations are performed to determine the appropriate Target Reserve Margin: a risk-adjusted economic optimal analysis; and the determination of a minimum reliability threshold. It is common industry practice to determine an appropriate reliability threshold by planning for an annual Loss of Load Expectation ("LOLE") of no greater than 0.1 days per year - or one event in ten years ("1:10 LOLE"). Because the annual LOLE threshold includes both winter and summer seasons, a reliability change in one season can impact the Target Reserve Margin in the other season if the maximum 1:10 LOLE threshold is to be maintained.

Except for the 2018 Reserve Margin Study, the annual 1:10 LOLE threshold within the System has historically occurred at reserve margins at or below the economic optimal recommendation. Thus, the primary focus has historically been on the economic analysis to establish the Target Reserve Margin. However, as the Company continues to update reliability risks in its modeling, the 2024 Reserve Margin Study has indicated that the LOLE for the System, particularly in the winter season, is higher than in years past. Thus, the seasonal Target Reserve Margins necessary to maintain the 1:10 LOLE threshold are also higher. The primary reason is that more recent winter weather events had sustained higher loads across overnight hours, increasing the need for more energy throughout these events. The Company's Reserve Margin Study in Technical Appendix Volume 1 provides additional explanation and context as to why the System LOLE is higher than years past.

The Company's final analysis for the winter-only season revealed that achieving a 1:10 LOLE threshold required a winter reserve margin of at least 25.75%, which is higher than the expected economic optimal case but still within the risk-adjusted confidence intervals considered. However, maintaining the current 26% Winter Reserve Margin Target with a 16.25% Summer Reserve Margin Target results in an annual LOLE of one event in eight years, well below the 1:10 LOLE threshold. Therefore, either the Winter Target Reserve Margin or the Summer Target Reserve Margin must be increased to ensure an adequate level of annual reliability on the System.

Since resources procured for the winter season are also typically available in the summer season, the equivalent Summer Target Reserve Margin that corresponds to the 26% Winter Target Reserve Margin is 24.76% in the Reserve Margin Study. Therefore, raising the Summer TRM to 20% is not expected to drive a System capacity need. One or more Operating Companies may, however, have a summer capacity need in a given year. Section 8.1 provides details on Georgia Power's seasonal capacity needs.

For the short-term, the System plans to adopt a Summer Target Reserve Margin of 19.5% and maintain a short-term Winter Target Reserve Margin of 25.5%. A significant benefit of coordinated System planning and operations, which allow companies to share resources, is that each Operating Company can carry fewer reserves than the System target. Thus, the Summer Target Reserve Margin that will apply to Georgia Power will be 19.09% over the long-term and 18.58% over the short-term. Likewise, Georgia Power's proposed Winter Target Reserve Margin will be 25.13% over the long-term and 24.61% over the short-term. These targets can change as System load diversity changes.

6.2 – Reliability Planning Model

The 2024 Reserve Margin Study included in Technical Appendix Volume 1 was performed using the Strategic Energy and Risk Valuation Model ("SERVM"). SERVM is an industry-leading generation reliability model used for Resource Adequacy analyses and is further described in Attachment E.

6.3 – Capacity Equivalence

The capacity value of renewable resources and other energy-limited or non-dispatchable resources is often represented in the utility industry by the effective load carrying capability ("ELCC") of the resource. As detailed in the 2022 IRP, the Company has adopted the widely used form of ELCC, which determines the reliability value of a resource by its ability to serve load while keeping reliability, as measured by LOLE, the same.

6.4 – Renewable Integration Study

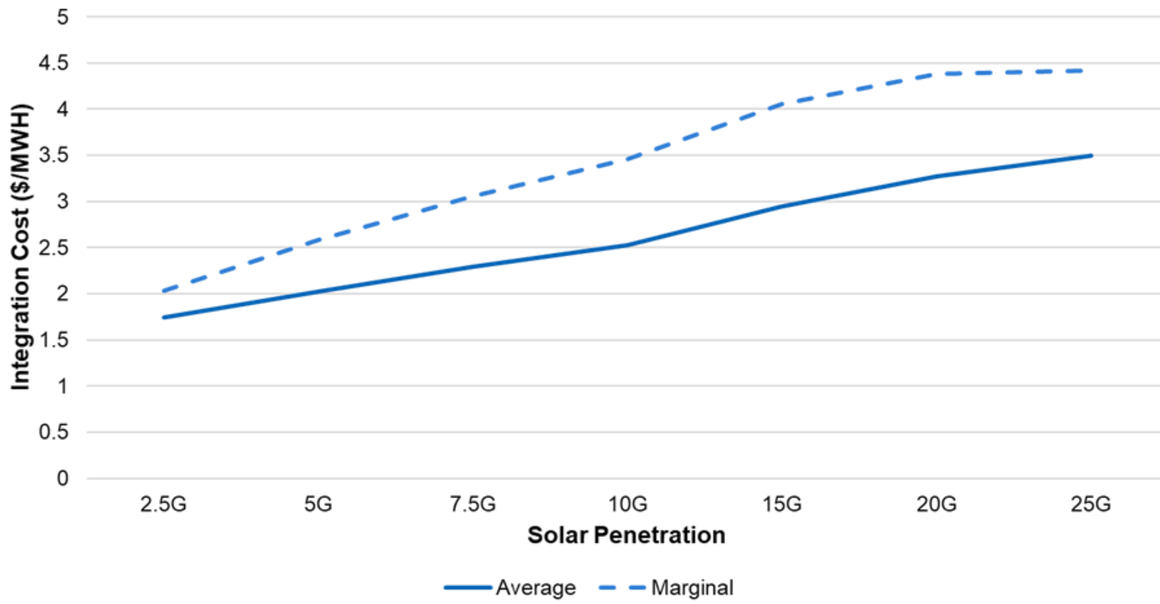
Ensuring a reliable fleet transition necessitates continued forward-thinking and innovative reliability solutions. The Company has completed an updated Renewable Integration Study with these objectives in mind. Specifically, the Company evaluatedefit the reliability impacts of large solar penetration levels from an operational perspective. This assessment provides unique insights into certain challenges, opportunities and, most importantly, solutions that enable significant renewable penetration while maintaining a reliable System.

System operators commit and dispatch the System with a focus on maintaining reliability. To ensure reliable operation, operators must balance load and generation in real-time while managing inherent load and generator uncertainties. Operating reserves serve as a vital tool for System operators in managing these uncertainties. Operating reserves represent the capacity above real-time load requirements that is available to respond to unexpected unit outages, variability in loads or resource output, or similar unpredictable changes in System conditions. Operating reserves can be provided by resources that are either on-line or on-standby. As the System becomes increasingly reliant on intermittent, weather-dependent renewable resources, operating reserves will become an increasingly important consideration for reliability planning and the successful integration of renewable resources.

To identify the potential changes in the required operating reserves, the Company also completed an updated intra-hour reliability assessment of renewable penetration levels that present reliability issues. The Company once again completed this study using the reliability planning model, SERVM, with industry expertise support provided by Astrapé. This study is further described in Technical Appendix Volume 2.

This study indicates that significant increases in solar penetration can be achieved while maintaining appropriate levels of reliability for the System. However, the cost of integrating renewable resources while maintaining System reliability can be significantly reduced with the addition of flexible resources, such as BESS. The reliability assessment determined that maintaining sufficient amounts of stand-alone battery capacity significantly improves the cost-effectiveness of solar integration while reducing the curtailment of renewable resources and improving System reliability by providing critical grid reliability services. The updated study also includes a BESS breakeven component that identifies the amount of BESS that neutralizes the reliability impacts of each tranche of solar evaluated. As the energy landscape continues to evolve and additional information becomes available, the Company will continue to update these types of reliability assessments to ensure it appropriately plans for System reliability. The results of the Renewable Integration Study are summarized in Figure 6.4.

Figure 6.4: Solar Integration Costs[31]



[31] "G" on the x-axis represents x 1,000 MW (Ex: 5G = 5,000 MW of nominal solar).

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Chapter 7. Demand-Side Strategy

This chapter summarizes the process used to assess demand-side resources for the 2025 IRP and addresses the following topics:

- A review of significant events since the Company's 2022 IRP and 2023 IRP Update that are relevant to the screening and assessment of demand-side resources
- A summary of newly proposed DSM programs, changes to existing programs, and recommended decertification of programs
- A discussion of the regulatory treatment of DSM program costs and the additional sum
- A presentation of the economic results of DSM programs for the 2025 IRP using the moderate gas, lower carbon pressure ("MG0") and 111-MG0 scenarios

The identification and evaluation of demand-side resources for inclusion in this IRP involves market considerations, such as customer acceptance and applicability, customer economics and affordability, ability to implement programs, and electric supply economics using marginal cost calculations. As outlined in the 2022 IRP Order, the Company followed the process defined in the Commission's IRP rules and the DSM Program Planning Approach, which are discussed in more detail below.

7.1 – Review of Significant Events Since the 2022 IRP and 2023 IRP Update

Since the 2022 IRP and 2023 IRP Update, the following events have influenced Georgia Power's screening of demand-side resources:

- Consistent with the requirements of the Vogtle Prudence Order, the level of energy efficiency in the Company's Proposed Case was set to 0.75% of total energy sales
- The marginal costs of generating energy have increased, which, all things being equal, has led to an improvement in avoided cost benefits provided by DSM programs
- The Thermostat DR program was expanded to a target of 50,000 devices as a result of the 2023 IRP Update

7.1.1 – 2022 IRP and 2023 IRP Update Final Orders

In the 2022 IRP Order, the Commission decertified two programs, amended the certificates of ten programs, and certified one new program in the Company's DSM portfolio. In addition, the Commission ordered that the energy savings targets for both the residential and commercial programs be increased by 15% and the relative program budgets increased by 11% from the Company's original proposal. The 2022 IRP Order approved program plans for the following programs:

Residential Programs:

- Behavioral
- Home Energy Improvement
- Specialty Lighting
- Refrigerator Recycling Plus
- Energy Assistance for Savings and Efficiency (previously, HEEAP)
- Thermostat Demand Response
- HopeWorks

Commercial Programs:

- Custom
- Prescriptive
- Small Commercial Direct Install
- Behavioral (program approved for two years per stipulation and subject to pausing in the third year if evaluation results do not find program to be cost effective)

To address capacity needs identified in the 2023 IRP Update, the Company requested to expand the Thermostat DR program. The 2023 IRP Update Order approved the expansion of the Thermostat DR program to 50,000 devices, up from 25,000 devices, and increased the demand-savings goal from 18.5 MW to 37 MW in 2024 and 2025.

7.1.2 – Program Evaluation Results

To evaluate its programs as required by the 2022 IRP Order, the Company selected BrightLine Group and Illume Advising, for commercial and residential program evaluations, respectively. The evaluators developed evaluation plans, which the Company shared with Commission Staff in 2023. Program evaluation results were then provided to Commission Staff between July 15 and September 25, 2024. These results were considered in the development of the 2025 IRP, as well as the program plans in the Company's 2025 DSM Application in Docket No. 56003.

7.1.3 – DSM Program Planning Approach

In accordance with the 2019 and 2022 IRP Orders, the Commission-approved a nine-step DSM Planning Process (renamed the "DSM Program Planning Approach") to guide the development of the Company's 2025 IRP and DSM Certification plans. The Company adhered to the DSM Program Planning Approach, met with the DSM Working Group ("DSMWG") eight times between 2023 and 2024, and engaged with the DSMWG to collaboratively develop program concepts for the 2025 IRP. The Company also met with DSMWG subcommittees in 2024 to discuss DSM program concepts for the Proposed Case and modeling a DSM sensitivity case proposed by certain members of the DSMWG. Finally, the Company shared data with the DSMWG in preparation for, and leading up to, the 2025 IRP filing.

7.1.4 – IRP Avoided Cost

The overall increase in System costs has increased the marginal cost of generating and delivering energy since the 2022 IRP. Today, equivalent levels of energy efficiency yield greater avoided costs.

With these higher avoided costs, the value of each kWh saved from DSM participation has increased since the 2022 IRP.

These increases in avoided cost savings positively impact the economics of the Company's DSM programs. At the same time, the costs of achieving the required energy efficiency levels in the Company's Proposed Case have increased, which results in negative TRC test results for some programs. As reflected in the Company's Proposed Case, overall TRC Test results declined while Rate Impact Measure ("RIM") results remained negative. This increases concerns for the Company, as it must balance the benefits these programs provide for participating customers with the rate impacts to customers as a whole.

7.2 – Discussion of Current and Proposed DSM Programs

7.2.1 – Residential DSM Programs

In its 2025 DSM Application, the Company requests the following actions or adjustments for each of the residential DSM programs in the Company's Proposed Case:

Table 7.2A: 2025 DSM Residential Certification Requests

Residential Program	Status	Action Requested
Products	New	Grant a New Certificate
Home Energy Improvement	Existing	Certificate Amendment and Waiver Requested
Energy Assistance for Savings and Efficiency	Existing	Certificate Amendment and Waiver Requested
HopeWorks	Existing	Certificate Amendment and Waiver Requested
Behavioral	Existing	Certificate Amendment
Demand Response	Existing	Certificate Amendment
Refrigerator Recycling Plus	Existing	Decertify
Specialty Lighting	Existing	Decertify

Program details are included the Company's 2025 DSM Application, Docket No. 56003. Additional details regarding the waiver and decertification requests for the programs are provided below.

Residential Programs Requesting a Waiver

The Company proposes continuing the Home Energy Improvement, Energy Assistance for Savings and Efficiency, and HopeWorks programs, considering the value these programs provide to market-rate and income-qualified customers. While these requested existing Residential programs have demonstrated high customer satisfaction and market potential, due to the costs required to achieve the large energy savings goal resulting from the Vogtle Prudence Order, the programs do not reflect positive TRC results for the 2025 IRP cycle. Therefore, as discussed further in the 2025 DSM

Application, Georgia Power requests a waiver of the TRC requirement within Commission Rule 515-3-4-.04(4)(a)(3) to continue these DSM programs.

Residential Programs Requesting Decertification

Refrigerator Recycling Plus

The Company requests decertification of the Refrigerator Recycling Plus Program. Appliance recycling is no longer cost effective, as appliances recycled in recent years are of newer vintage, resulting in lower energy savings, while the cost of recycling has either remained the same or increased. Additionally, there are limited appliance recycling vendors in business, making it difficult to implement a recycling program.

Specialty Lighting

The Company requests decertification of the Specialty Lighting Program. Market transformation and federal regulations have made energy-efficient lighting measures readily available to all consumers. Therefore, incentivizing lighting measures through programs is no longer cost effective due to diminishing energy savings.

7.2.2 – Increased Income-Qualified Initiatives

The Company's Proposed Case expands DSM offerings to income-qualified customers with additional program measures and increased energy savings goal. The Company seeks recertification for Energy Assistance for Savings and Efficiency ("EASE") and HopeWorks, and expands income qualification criteria for EASE to include moderate-income customers, which helps increase program participation for customers who can benefit the most from program energy savings.

7.2.3 – Commercial DSM Programs

In its 2025 DSM Application, the Company requests the following actions or adjustments for each of the commercial DSM programs in the Company's Proposed Case:

Table 7.2B: 2025 DSM Commercial Certification Requests

Commercial Program	Status	Action Requested
Custom	Existing	Certificate Amendment and Waiver Requested
Prescriptive	Existing	Certificate Amendment
Small Commercial Direct Install	Existing	Certificate Amendment
Behavioral	Existing	Decertify

Program details are included in the 2025 DSM Application, Docket No. 56003. Details regarding program waiver and decertification requests are provided below.

Commercial Program Requesting a Waiver

Custom

The Company requests to continue the Commercial Custom program due to its high customer satisfaction and market potential for energy savings. The program does not reflect positive TRC results for the 2025 IRP cycle due to the costs needed to achieve the large energy savings goal in the Vogtle Prudence Order. Therefore, as discussed in the 2025 DSM Application, Docket No. 56003, Georgia Power requests a waiver of the TRC requirement within Commission Rule 515-3-4-.04(4)(a)(3) to continue this program.

Commercial Program Requesting Decertification

Behavioral

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

7.2.4 – Learning Power Education Initiative

Since 2011, the Company has delivered the Learning Power Education Initiative curriculum throughout the state of Georgia. The curriculum 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.

Since program inception, the Company has delivered 42,124 programs to 1,302,374 students through December 31, 2024.

In the Fall of 2020, virtual-live, student self-paced, and pre-recorded lessons were added to the Learning Power portfolio to meet the needs of schools and educators. Virtual platforms were used to deliver 4,034 lessons, reaching 136,720 students.

From January 1, 2022, through December 31, 2024, the Learning Power Initiative has delivered 8,444 programs to 386,782 students. Approximately 1,418 teachers responded to Georgia Power's post-lesson survey. Results of the survey are as follows on a scale of 1 - 5 with 1 being strongly disagree and 5 being strongly agree.

Table 7.2C: Learning Power Education Initiative – Post Lesson Survey Results

Survey questions	**Responses**
This lesson effectively taught energy efficiency and conservation concepts to my students	4.77
This lesson connected well with my students	4.79
I would recommend Learning Power lessons to other teachers	4.82
This lesson aligned with the Georgia Standards of Excellence	4.82
Did this lesson introduce age-appropriate career opportunities in the energy industry?	97% responded yes

7.2.5 – Energy Efficiency Awareness Initiative

The Company's Energy Efficiency Awareness Initiative promotes the benefits of energy efficiency and educates customers about ways to save energy. In the 2016, 2019, and 2022 IRPs, the Commission approved a dedicated budget for residential and commercial awareness. The Company is requesting continued funding for these efforts, which increase energy efficiency awareness for residential and commercial customers.

The Company uses multiple marketing channels to reach its customer base, including television, radio, print, web, digital, out of home, social media and media sponsorships. Social media channels include Meta, Instagram, LinkedIn, and YouTube. The Company has also developed several online tools to enhance customers' education and awareness about energy efficiency. Georgia Power encourages customers to visit its website at www.georgiapower.com/energyefficiency or www.georgiapower.com/commercialsavings to learn ways to save energy through general energy efficiency information, helpful tips, and specific information about energy efficiency programs offered by the Company.

In 2023 and 2024 J.D. Power Customer Satisfaction Surveys, the Company's dedicated awareness campaigns continue to lead in customer satisfaction among peer utilities and the national averages. Specifically, the Company leads peers and national averages for percentage of customers who say the utility helped lower their bill by showing how to conserve energy, for overall awareness of energy efficiency/conservation programs, and for variety of energy efficiency programs offered for both residential and commercial customers. Additionally, the energy efficiency awareness initiative garnered significant coverage across traditional, digital, and social media channels with 242,415,099 media impressions in 2023 and 303,286,386 in 2024 for residential customers and 27,284,588 media impressions in 2023 and 48,950,852 in 2024 for commercial customers.

7.2.6 – Pilot Studies

Georgia Power engages in pilot studies to better understand emerging energy efficiency and demand response options for the benefit of customers. In the 2019 and 2022 IRP, the Commission approved a $3 million annual budget for DSM energy efficiency pilot programs. Since 2023, 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 the 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 and continue to focus on enabling historically under-represented customers and small and medium businesses access and participation in energy efficiency programs.

In the 2025 IRP, the Company is seeking Commission approval of a $1.5 million budget for residential pilots and $1.5 million budget for commercial pilots, as outlined in the supporting documents included in Company's 2025 DSM Application.

7.3 – DSM Resource Assessment and Initial Cost-Effectiveness Screening

7.3.1 – Assessment and Screening Methodology

The assessment and screening methodology for DSM measures in this IRP included identifying DSM measures and programs with input from the DSMWG. Economic evaluations were performed for each measure and program to determine program cost-effectiveness based on industry-standard benefit/cost tests, as required by the Commission IRP rules. The tests include RIM Test, TRC Test, Participants Test ("PT"), Program Administrator Cost Test ("PACT"), and Societal Cost Test ("SCT"). The RIM Test measures the impact to customers' rates due to changes in utility revenues and operating costs caused by a program. The TRC Test measures the net costs of a DSM program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The PT assesses the impact on a program participant by measuring the quantifiable benefits and costs to the customer due to participation in a program. The PACT assesses the net costs of a DSM program as a resource option based on the costs incurred by the program administrator (including incentive costs) excluding any net costs incurred by the participant. The SCT is a variant of the TRC Test and includes an adder to avoided fuel costs to simulate environmental externalities.

The Company met with the DSMWG eight times in 2023 and 2024 regarding DSM program design details. A smaller sub-group of the DSMWG met and identified the program concepts and measures considered for economic screening in support of the 2025 IRP development. The sub-group's input was used in developing the list of programs and measures to analyze. This list was shared with the larger DSMWG for solicitation of additional feedback. Certain members of the DSMWG reached agreement regarding some of the programs to be included in the analysis of the DSMWG Advocacy Case. In addition, the preliminary results of the program economic screening were shared with the DSMWG in 2024.

7.3.2 – DSM Program Economic Screening Policy

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's DSM plan treats DSM as a priority resource. In fact, the first step in the Company's IRP process is to reduce the Company's load and energy forecasts by the Proposed Case's energy and demand impacts, prior to developing supply-side alternatives.

Economic screening for DSM programs in the 2025 IRP was completed using two scenarios – 111-MG0 and MG0. Chapter 3 provides additional information on these scenarios. The Proposed Case's cost-effectiveness results reflect either the continuation of, or modifications to, certain current DSM programs, the addition of a new DSM program, and the decertification of certain existing DSM programs. With the increased DSM program goals and costs resulting from the Vogtle Prudence Order, in which Georgia Power agreed to propose in the 2025 IRP a base case of DSM performance savings targets of at least 0.75% of annual retail sales, the rate impacts for the proposed programs will be significantly larger than those approved in the 2022 IRP Order. The net TRC benefits and RIM impacts of energy efficiency programs in the Company's Proposed Case for the 2025 IRP for years 2026-2028 are listed in Table 7.3 below.

Due to the significant upward pressure on rates resulting from the Proposed Case, the Company developed a Capacity and Affordability Case sensitivity. The Capacity and Affordability Case is intended to address customer affordability and capacity constraints and substantially mitigates the upward pressure on rates associated with the Proposed Case.

The Company also developed the Supply-Side sensitivity as required by the 2022 IRP Order. The Supply-Side sensitivity includes programs from the Proposed Case that are modeled in the Company's supply-side model, Aurora, to determine which programs are cost-effective when compared to other supply-side resources. Aurora evaluates resources on a net present value basis and does not provide TRC and RIM results. At the request of some DSMWG members, the Company agreed to analyze the DSMWG Advocacy Case, which assumes significantly higher levels of cumulative energy savings. The DSMWG's Advocacy Case reflects similar levels of energy savings targets included in the Company's Proposed Case, as well as an additional industrial program proposed by certain members of the DSMWG.

The higher levels of market penetration in the DSMWG's Advocacy sensitivity case ultimately results in increased upward rate pressure for years 2026-2028, as seen in Table 7.3 below. In addition, the DSMWG's Advocacy sensitivity case also includes an industrial DSM program, which runs counter to the Commission's position on the exclusion of industrial DSM programs from prior IRPs. For these reasons, the Company did not use the DSMWG Advocacy Case and recommends that the Commission not adopt it either. The net TRC benefits and RIM impacts of energy efficiency programs in the various DSM cases for the 2025 IRP are listed in Table 7.3 below.

Table 7.3: TRC and RIM Impacts of DSM Cases for 2026-2028 (NPV in millions)

DSM Cases	MG0 scenario		111-MG0 scenario	
	TRC net benefits	RIM impacts	TRC net benefits	RIM impacts
Proposed Case	-$16 to $3	-$630 to -$746	-$3 to $24	-$609 to -$733
Advocacy Case	-$12 to $8	-$641 to -$761	$1 to $29	-$620 to -$748
Supply-Side Case*	N/A	N/A	N/A	N/A
Capacity and Affordability Case	$80 to $92	-$162 to -$211	$84 to $100	-$154 to -$206

* The supply-side model, Aurora, evaluates resources on a net present value basis and does not provide TRC or RIM results.

7.3.3 – Data Development

In developing its list of DSM measures for initial screening, the Company conducted a comprehensive review of technical information sources for demand-side and energy efficiency technologies. The Company evaluated its previous IRP filings, as well as new sources of information, such as industry conferences and trade associations. Input was provided by the DSMWG, which has members with years of experience in DSM program development and implementation. Company representatives who work closely with Georgia Power's customers also provided input. The Company shared the information it gathered with the DSMWG in program development discussions. The results of the qualitative screening are set forth in DSM Program Documentation in Technical Appendix Volume 1.

7.3.4 – Residential Technology

One hundred residential DSM measures were identified for economic screening and possible inclusion in residential programs. These measures provide potential energy savings through:

- Increased energy efficiency for electric equipment
- Electric space cooling and heating equipment
- Electric lighting
- Electric water heating
- Customer behavior improvements
- Heating and cooling savings resulting from improvements to the homes thermal shell

In addition to specific measures, building type (single family – new and existing; multifamily – new and existing; or manufactured housing – new and existing) was considered in the economic analysis.

7.3.5 – Commercial Technology

More than 120 commercial DSM measures were identified for economic screening and possible inclusion in commercial programs. These measures provide energy savings through:

- Increased energy efficiency for electric equipment
- Electric space cooling and heating equipment
- Electric lighting
- Electric water heating
- Customer behavior improvements
- Heating and cooling savings resulting from improvements to the building's thermal shell

In addition to specific measures, building type (the type of customer operation, such as schools or offices) was considered along with the construction type (new and existing) when conducting the economic analysis.

7.3.6 – Industrial Technology

The Company's Proposed Case does not include industrial programs 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. Nevertheless, an industrial pilot program was included in the DSMWG Advocacy sensitivity case.

7.3.7 – Economic Screening

Energy consumption and savings were calculated for all measures that were passed to economic screening. First, the energy usage characteristics for weather-sensitive HVAC and thermal shell measures were calculated using both algorithms and an engineering simulation model ("OpenStudio/EnergyPlus™"), which is described in Attachment E. Then, each potential measure passed to economic screening and was evaluated with the Profitability Reliability Incremental Cost Evaluation Model ("PRICEM"), which is also described in Attachment E.

The RIM Test, the TRC Test, the PT, the PACT, and the SCT were applied to each measure and program. Additionally, the Cost of Saved Energy ("CSE"), also referred to as Levelized Cost per annual kWh saved, is provided for each program screened. The CSE is the total cost per kWh of realizing the efficiency improvement. CSE is determined by dividing levelized program costs by the annual energy savings, as shown in the following equation. Levelized program costs are calculated using a Capital Recovery Factor, which incorporates the number of years that the energy savings persist, and an annual discount rate.

CSE Equation:

$$CSE = \frac{Program\ Costs\ (\$) \times CRF}{Annual\ Energy\ Savings\ (kWh)}$$

7.3.8 – Long-Term Percentage Rate Impacts

The Company analyzed the long-term percentage rate impact of its DSM Proposed Case, as well as the Advocacy, and Capacity and Affordability sensitivity cases. The DSM Program Documentation section of Technical Appendix Volume 1 contains results of the long-term percentage rate impacts.

7.4 – Demand-Side Program Development

7.4.1 – Demand-Side Resource Policy

In the 2004 IRP Order, the Commission directed that the Company's proposed DSM plans should minimize upward pressure on rates (negative RIM results) and maximize economic efficiency (positive TRC results). The Commission further directed that the cost/benefit analysis results of each initiative should use the five tests mentioned above and should balance economic efficiency (TRC benefits) with fairness and equity (RIM benefits/cost). As in each IRP since 2004, the Company applied this Commission policy in analyzing the programs for the 2025 IRP and developed the DSM Proposed Case with a savings target of at least 0.75% of annual retail sales, in accordance with the Vogtle Prudence Order. As noted above, the Company also adhered to the DSM Program Planning Approach in developing the 2025 IRP.

7.4.2 – Twelve-Year DSM Program Plans

The Company developed twelve-year program plans outlining the implementation details behind each individual program in its Proposed Case. The program plans are provided in the 2025 DSM Application.

The following details are included in each program plan:

- Program Summary – outlines the goals of the program
- Program Structure – outlines the intended participant eligibility, home or facility eligibility, and specific measures and incentives where appropriate
- Program Implementation – outlines the intended target market, key market players, as well as marketing and outreach plans
- Program Operation – outlines the intended customer participation process and program administrative procedures
- Program Evaluation – outlines the intended performance metrics, expected program budget, cost-effectiveness expectations, as well as plans to develop an independent third-party evaluation plan after programs are approved

Each of the twelve-year DSM program plans allow for ongoing review and modification of program design features through regular monitoring. In addition, a formal program evaluation is conducted at the end of the program cycle. Any significant changes to program design in support of market conditions or program economics will be included in ongoing reports filed with the Commission, program evaluation filings, and/or any future IRP updates. Additionally, as new measures and technologies evolve during the twelve-year program life, the Company may add such measures to these programs. Any new measures being added will follow the same economic screening process as those approved by the Commission, and the Commission would be made aware of any additions prior to the Company offering the new measures to customers as required.

7.5 – Regulatory Treatment of DSM Program Costs and the Additional Sum

The Company requests the continued collection of costs for all approved and certified DSM programs and activities through the existing Residential and Commercial DSM tariffs. These tariffs will be filed as part of the Company's next base rate case and would be implemented with any approved change in rates on January 1, 2026. The Company also requests the continued collection of an additional sum amount for certified energy efficiency programs with energy savings through these tariffs pursuant to a revised additional sum calculation methodology presented in the Company's DSM Certification Application in Docket No. 56003.

7.6 – Summary of DSM Cases

The Company has developed the Proposed Case at portfolio energy savings targets of 0.75% of annual retail sales, in accordance with the Vogtle Prudence Order. Additionally, the Company developed three alternative DSM sensitivity cases. The first alternative sensitivity case, the Advocacy Case, presents a potential set of DSM programs designed based on the recommendations from members of the DSMWG. The second alternative sensitivity case represents the Supply-Side Case which is outlined in the DSM Program Planning Approach and stipulated in the 2022 IRP Order. The third alternative sensitivity case, Capacity and Affordability Case, was developed by the Company based on the Proposed Case and its intentional efforts to focus on customer affordability concerns and capacity constraints. Table 7.6 below outlines the programs offered in these cases for the years 2026-2028, “X” indicates program inclusion under both MG0 and 111-MG0 economic scenarios while “111-MG0” indicates program inclusion in just the 111-MG0 economic scenario. Additional details on these programs can be found in the 2025 DSM Application, Docket No. 56003, Appendix A Twelve-Year DSM Program Plans. Further, program savings targets and budgets can be found in DSM Program Documentation section of Technical Appendix Volume 1, DSM Case Summary Data MG0 and 111-MG0.

Table 7.6: Program Inclusion Overview of DSM Cases

Programs	Proposed Case	Advocacy Case	Supply-Side Case	Capacity & Affordability Case
Products Program	X	X	111-MG0	
Home Energy Improvement Program (HEIP)	X	X	111-MG0	
Energy Assistance for Savings and Efficiency (EASE)	X	X	111-MG0	X
Demand Response Program (DR)	X	X		X
Residential Behavioral	X	X	X	X
HopeWorks	X	X		X
Commercial Custom Program	X	X	X	
Commercial Prescriptive Program	X	X	X	X
Small Commercial Direct Install Program (SCDI)	X	X	X	X
Industrial Custom Program		X		

7.6.1 – Proposed Case

The net TRC benefits and RIM impacts of energy efficiency and demand response programs in the Company’s Proposed Case for the 2025 IRP are listed in Table 7.3 above. The energy efficiency and demand response programs in the Company’s Proposed Case for the 2025 IRP 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 and approximately

-$3 to $24 million in annual net TRC benefits while putting upward pressure on rates of approximately $609 to $733 million annually under the 111-MG0 economic scenario over years 2026 - 2028. Nevertheless, the Company supports the DSM programs as described above and included in the 2025 DSM Application, to achieve the levels of energy savings approved by the Commission in the Vogtle Prudence Order. If approved, the Company plans to continue these programs to minimize market disruption, to continue meeting customers' expectations, and to maintain positive relationships with vendors performing qualified program improvements. The Company's DSM portfolio included in the 2025 IRP consists of currently certified programs as well as a new program, modified based on data gathered in the implementation phase, as well as input from the DSMWG and an independent third-party evaluation. The Proposed Case will continue to enhance these programs as more information becomes available relative to market penetration and customer feedback through an ongoing evaluation process. The Company will keep the Commission fully informed of potential changes to programs through notification to, or approval by, Commission Staff, as appropriate.

The Company's Proposed Case economics are provided in the DSM Program Documentation section of Technical Appendix Volume 1. Considering the significant upward pressure on rates resulting from the Proposed Case, the Company developed a Capacity and Affordability Case sensitivity, identified in Section 7.6.4 below, which substantially mitigates the upward pressure on rates associated with the Proposed Case.

7.6.2 – DSMWG Advocacy Case

The DSMWG Advocacy Case was developed as a sensitivity case to the Company's Proposed Case and is based on requests made by certain members of the DSMWG. The Company presents the results of this case for informational purposes. If the DSMWG Advocacy Case were to be implemented, the portfolio would put upward pressure on rates, as listed in Table 7.3 above, of approximately $641 to $761 million annually under the MG0 economic scenario and approximately $620 to $748 million annually under the 111-MG0 economic scenario for years 2026 - 2028. The DSMWG Advocacy Case is similar to the Company's Proposed Case but includes an industrial program. As previously explained, the Company does not support the inclusion of an industrial program because it is not necessary to incentivize industrial customers and would unnecessarily increase costs. Therefore, the Company does not recommend approval of the DSMWG Advocacy Case.

The DSMWG Advocacy Case summary tables are provided in the DSM Program Documentation section of Technical Appendix Volume 1.

7.6.3 – Supply-Side Case

The Supply-Side Case was developed as a sensitivity case as outlined in the DSM Program Planning Approach and stipulated in the 2022 IRP Order. In this case, DSM programs were modeled alongside supply-side resources, such that the most cost-effective combination of supply-side resources and DSM are identified to reliably meet load. Per the 2022 IRP Stipulation, the Supply-Side Case replaces the Aggressive Case in the DSM Program Planning Process for the 2025 IRP. The Company's supply-side modeling system, Aurora, evaluates resources on a relative net present value basis, and therefore comparisons to traditional DSM cost-effectiveness tests are not applicable. For both the

MG0 and 111-MG0 scenarios, the supply-side system more often selected commercial programs over residential programs as being cost-effective. In the MG0 scenario, no income-qualified programs were selected by the supply-side system in the years 2026-2028. The Company does not recommend approval of the Supply-Side Case. The Supply-Side Case summary tables are provided in the DSM Program Documentation section of Technical Appendix Volume 1.

7.6.4 – Capacity and Affordability Case

The Capacity and Affordability Case is a sensitivity case developed by the Company as an alternative to the Proposed Case and is intended to address customer affordability and capacity constraints. The Company's Capacity and Affordability Case for the 2025 IRP achieves approximately $80 to $92 million annually in net TRC benefits for years 2026-2028 while putting upward pressure on rates of approximately $162 to $211 million annually under the MG0 economic scenario and approximately $84 to $100 million annually in net TRC benefits while putting upward pressure on rates of approximately $154 to $206 million annually under the 111-MG0 economic scenario over years 2026 - 2028, as listed in Table 7.3 above. The Capacity and Affordability Case strikes a balance between customer affordability concerns, capacity constraints, and the value of energy efficiency programs. Programs in the Capacity and Affordability Case are subsets of the Company's Proposed Case and certified programs currently in market, modified based on data gathered in the implementation phase and an independent third-party evaluation. If the Commission prefers to go in this direction, the Company will continue these programs to minimize market disruption while continuing to meet customers' expectations. The Capacity and Affordability Case also includes an online residential energy audit tool to help customers understand their energy usage and help address and alleviate affordability concerns. In addition, the case includes a small team of energy experts (auditors) to further assist residential customers with advanced energy usage, comfort and affordability issues. The Capacity and Affordability Case will continue to enhance the DSM programs as more information becomes available relative to market penetration and customer feedback through an ongoing evaluation process.

7.7 – DSM Action Plan

In summary, the Company's DSM Action Plan for the Proposed Case includes the following items detailed in Section 7.2:

- Implementation of the six residential and three commercial DSM programs
    - Continuation of Home Energy Improvement, Energy Assistance for Savings and Efficiency (EASE), HopeWorks and Custom programs in the 2025 IRP cycle pursuant to a waiver of the TRC requirement in Commission Rule 515-3-4-.04(4)(a)3
    - Certification of residential Products Program
- Decertification of the residential Refrigerator Recycling Plus and Specialty Lighting and commercial Behavioral programs
- Continuation of the Learning Power Education and Energy Efficiency Awareness initiatives
- Continuation of pilot studies and approval of the annual pilot budget

Chapter 8. Supply-Side Strategy

This Chapter outlines the comprehensive supply-side strategy designed to enhance the reliability, flexibility, and value of resources to serve customer needs. In addition to the continued operation of Plant Bowen Units 1-4, key elements of this strategy include the following:

- Resource Extensions: Includes extending operation of six existing generating units.
- Resource Upgrades: Includes upgrade projects for 14 gas and nuclear units.
- Hydro Modernization: Includes investment in 42 hydroelectric units.
- Flexible Procurement: Proposed changes to renewable procurement processes, including RFP process enhancements and additional customer subscription options.

The 2025 IRP supply-side strategy provides customers with substantial reliability and economic benefits by leveraging opportunities from existing resources and continuing to enhance the Company's procurement processes and program offerings. With the 2025 IRP, the Company is seeking approval of the following actions to serve customers, as detailed further in this Chapter.

- Preserve 1,007 MW of reliable existing operating capacity, beginning in the winter of 2028/2029 through extending the operation of six generating units:
  - **Extend Plant Scherer Unit 3** beyond December 31, 2028, assuming operation of this unit through 2035 or 2038, depending on the planning scenario. A request for return of 187 MW of wholesale capacity from Plant Scherer Unit 3 to retail service.
  - **Extend Plant Gaston Units 1-4 and A** beyond December 31, 2028, and assume operation through the end of 2034.
- Upgrade 14 existing generating units to add a projected 380 MW of capacity at already built and operating resources:
  - **Upgrade Plant McIntosh Units 10-11** to obtain a projected 194 MW of incremental capacity by the winter of 2028/2029.
  - **Upgrade Plant McIntosh Units 1A-8A** to obtain a projected 74 MW of incremental capacity, some of which would be available as early as the winter of 2027/2028.
  - **Upgrade Plant Hatch Units 1-2 and Plant Vogtle Units 1-2** to obtain a projected 58MW and 54 MW of incremental capacity, respectively, some of which would be available as early as the winter of 2028/2029.
- Maintain, invest in, and continue to operate nine existing emission-free hydroelectric resources, consistent with applicable FERC license requirements, totaling 665 MW of capacity:
  - **Plant Tallulah Units 1-6**. Preserve 73 MW.
  - **Plant Yonah Units 1-3**. Preserve 29 MW.
  - **Plant Lloyd Shoals Units 1-6**. Preserve 23 MW.
  - **Plant Wallace Units 1-6**. Preserve 328 MW including 213 MW of pumped storage.

   - **Plant Bartletts Ferry Units 5-6**. Preserve 121 MW.
   - **Plant Goat Rock Units 3-8**. Preserve 29 MW and restore 10 MW, as well as develop, own and operate a projected incremental 16 MW from Units 3-6 to correct a flow imbalance in the Chattahoochee Hydro Group.
   - **Plant North Highlands Units 1-4**. Preserve 35 MW.
   - **Plant Flint River Units 1-3**. Preserve 6 MW.
   - **Plant Morgan Falls Units 1-7**. Preserve 8 MW and restore 3 MW.
- Issue RFPs designed to procure energy from up to 4,000 MW of renewable resources by 2035, including the **2026 Utility Scale RFP** targeting 1,000 MW of utility-scale renewable resources expected to reach commercial operation between November 30, 2030, and November 30, 2032.
- Issue the **2026 and 2027 Distributed Generation RFPs**, each for 50 MW, for a total of 100 MW of distributed generation resources to reach commercial operation in 2027, 2028 and 2029.
- Implement changes to the **Utility Scale** renewable procurement process further detailed in Chapter 8 and Chapter 10.
- Implement changes to the **Distributed Generation** renewable procurement process further detailed in Chapter 8 and Chapter 10.

A list of Georgia Power's planned and committed resources is contained in Attachment C.

8.1 – Capacity Needs

The Company determines its capacity needs by comparing its forecasted demand and the existing, planned, and committed supply- and demand-side resources available to meet that demand. The capacity need is represented by the difference in megawatts between existing, planned, and committed supply- and demand-side resources and the forecasted annual peak demand plus target reserve margin requirements. The Resource Mix Study in Technical Appendix Volume 2 provides detailed information on the Company's capacity needs. Tables 8.1A and 8.1B are provided below for projected winter and summer capacity needs for years 2025 through 2044 for the 111-MG0 and MG0 planning scenarios for both Georgia Power and the Southern Company retail operating companies. While the Georgia Power capacity need in the summer exceeds that of the preceding winter until the summer of 2031, that is not the case with the System needs. This indicates Georgia Power may not need to add resources to fully address its own incremental summer capacity needs but rather could leverage other resources on the System.

Table 8.1A: Projected Seasonal Capacity Needs (MW) – 111-MG0

Winter			Summer		
Year	Georgia Power	Southern Retail Operating Companies	Year	Georgia Power	Southern Retail Operating Companies
2024/2025	(602)	(853)	2025	(898)	(3,867)
2025/2026	(781)	(1,602)	2026	(708)	(4,311)
2026/2027	(598)	(1,014)	2027	80	(3,527)
2027/2028	1,467	1,295	2028	2,132	(191)
2028/2029	4,086	5,329	2029	4,846	3,041
2029/2030	5,783	7,156	2030	7,568	5,801
2030/2031	8,948	10,508	2031	8,277	6,641
2031/2032	9,511	11,116	2032	8,680	7,043
2032/2033	9,954	11,702	2033	9,176	7,647
2033/2034	10,252	12,158	2034	9,522	8,118
2034/2035	12,290	14,688	2035	11,989	11,429
2035/2036	13,015	15,903	2036	12,290	11,832
2036/2037	13,351	16,273	2037	12,760	12,301
2037/2038	13,965	16,939	2038	13,224	12,770
2038/2039	19,057	22,391	2039	18,025	17,944
2039/2040	19,799	23,140	2040	18,515	19,316
2040/2041	20,284	24,603	2041	19,009	20,208
2041/2042	20,768	25,571	2042	19,484	21,042
2042/2043	21,299	26,572	2043	19,968	21,624
2043/2044	21,822	27,198	2044	20,536	23,060

Table 8.1B: Projected Seasonal Capacity Needs (MW) – MG0

Winter			Summer		
Year	Georgia Power	Southern Retail Operating Companies	Year	Georgia Power	Southern Retail Operating Companies
2024/2025	(602)	(853)	2025	(898)	(3,867)
2025/2026	(781)	(1,602)	2026	(708)	(4,311)
2026/2027	(598)	(1,014)	2027	80	(3,527)
2027/2028	1,467	1,295	2028	2,132	(191)
2028/2029	4,086	5,329	2029	4,846	3,041
2029/2030	5,783	7,236	2030	7,568	5,881
2030/2031	8,948	10,588	2031	8,277	6,721
2031/2032	9,511	11,196	2032	8,680	7,123
2032/2033	9,954	11,782	2033	9,176	7,727
2033/2034	10,252	12,238	2034	9,522	8,198
2034/2035	12,290	14,768	2035	11,989	11,509
2035/2036	16,980	19,949	2036	16,135	15,756
2036/2037	17,316	20,318	2037	16,605	16,225
2037/2038	17,930	20,984	2038	17,069	16,694
2038/2039	19,057	22,471	2039	18,025	18,024
2039/2040	19,799	23,220	2040	18,515	19,396
2040/2041	20,284	24,683	2041	19,009	20,288
2041/2042	20,768	25,651	2042	19,484	21,122
2042/2043	21,299	26,652	2043	19,968	21,704
2043/2044	21,822	27,278	2044	20,536	23,120

Notes:

- Tables 8.1A and 8.1B assume the extended operation of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and A beyond December 31, 2028. Both tables assume Plant Gaston operates through December 31, 2034.
- Table 8.1A assumes Plant Bowen and Plant Scherer units operate through December 31, 2038.
- Table 8.1B assumes Plant Bowen and Plant Scherer units operate through December 31, 2035.
- Neither Table 8.1A nor Table 8.1B reflects an assumed capacity procurement amount associated with the Winter 2027/2028 BESS RFP or the All-Source Capacity RFP for 2029-2031. This is to show the total procurement required from those RFPs to meet capacity needs from the winter of 2027/2028 through the winter of 2030/2031.
- Except for the extensions of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and A, none of the 2025 IRP incremental capacity requests are reflected in the tables above. Approval of such requests would serve to reduce capacity procurement required through the Winter 2027/2028 BESS RFP and the All-Source Capacity RFP for 2029-2031.

8.2 – Unit Retirements

With substantial load growth in Georgia and the comparative cost of developing or procuring replacement generation, the Company has updated its retirement plans for several generating units. Through extending the operation of several existing resources, the Company's updated plans are economic and cost effective, offering improved decision-making flexibility while providing the necessary capacity to maintain reliability and support the substantial economic development and load growth taking place in Georgia. The Company's economic analysis for these coal and gas-steam resources supports the continued operation of each resource, some of which were previously planned for near-term retirement in earlier IRPs.

The 2022 IRP recommended the decertification and retirement of Plant Scherer Unit 3, Plant Gaston Units 1-4, and Unit A by December 31, 2028. 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. At the time of the 2022 IRP, 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 low levels of load growth.

In the 2023 IRP Update, the Company highlighted Georgia's continued extraordinary economic development track record and the corresponding electric load growth. Considering the outcome of the 2023 IRP Update together with load growth projected in this 2025 IRP, the Company now projects capacity needs that necessitate both the extension of existing coal and gas-steam units along with the procurement of new capacity resources. Extending the operations of these existing generating units provides immediate economic value and efficiencies on the System, reducing the need to immediately construct new resources. The 2025 IRP updates the retirement dates for certain generating resources to ensure continued reliability and provide economic benefits for customers.

The Company's updated economic analysis included in the Unit Retirement Study in Technical Appendix Volume 1, evaluates the economic implications of new environmental regulations, including the Supplemental ELG Rule and the 111 GHG Rules, as further explained in Chapter 9. This analysis compares the costs and benefits of compliance pathways versus 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 is more cost effective and poses lower risk than retirement of these units. These factors inform the Company's recommendations:

- **Plant Bowen Units 1-4**: Continued operation of the units with investment in the necessary environmental controls is recommended. As discussed in Chapter 9, the two primary environmental rules requiring additional controls include the Supplemental ELG Rule regulating wastewater and the 111 GHG Rules regulating GHG emissions. The installation of ELG controls by December 31, 2029, is required to comply with environmental regulations and will preserve the ability to operate these units beyond 2034. Additionally, the ELG controls provide Georgia Power with 111 GHG Rules compliance flexibility, enabling the natural gas co-fire compliance pathway to be selected during the state plan development process. Notably, the co-fire pathway in the 111 GHG Rules permits operation until December 31, 2038, while reducing reliance on natural gas pipeline infrastructure and deferring the need for replacement capacity until 2039. This pathway is economically competitive compared to the other 111 GHG Rules compliance options and reduces the need to procure new capacity by 2032 or earlier. Moreover, maintaining dispatchable generation in north Georgia is crucial for transmission system reliability. Considering the uncertainty surrounding future environmental regulations and market conditions, this approach provides an economic, flexible, and adaptive strategy to ensure continued compliance and resource planning optionality.
- **Plant Scherer Units 1-3**: Continued operation of the units with investment in the necessary environmental controls is recommended. The selection of membrane-based technology for the ELG Reconsideration Rule, as recommended in the 2022 IRP, minimizes the incremental costs for Plant Scherer Units 1-3 under the Supplemental ELG Rule. Combined with other economic factors, this demonstrates that continued operation is cost effective. ELG control systems are required to maintain availability of the co-fire compliance pathway under the 111 GHG Rules, which permits extended operation until December 31, 2038, and defers the need for replacement capacity until 2039. It is economically competitive compared to the other compliance options and reduces the need to procure new capacity by 2032 or earlier. Considering the uncertainty surrounding future environmental regulations and market conditions, this approach provides an economic, flexible, and adaptive strategy to ensure continued compliance and resource planning optionality.
- **Plant Gaston Units 1-4 and A:** Plant Gaston Units 1-4, located in Alabama, are steam resources that primarily operate on natural gas, with limited coal backup to ensure reliable operation during periods of natural gas pipeline constraints, such as cold winter days. Plant Gaston Unit A is an oil-fired CT. Even after considering the age and necessary maintenance of these units, continued operation provides positive economic benefits to customers. Extending the operation of these units beyond December 31, 2028, can help preserve

capacity and add flexibility to the resource plan, given the ability to retire the capacity if projected load does not materialize. Considering the uncertainty surrounding future environmental regulations and market conditions, this approach provides an economic, flexible, and adaptive strategy to ensure continued compliance and resource planning optionality.

8.3 – Gas Unit Upgrades

The Company has identified opportunities to increase capacity at Plant McIntosh Units 10-11 and Units 1A-8A. These upgrades provide cost-effective solutions to meet customers' growing energy needs by leveraging existing operating generation resources and offering a balance of peaking capacity and NGCC capacity.

- **Plant McIntosh Units 10-11**: The upgrade opportunity being evaluated for the combined cycles at Plant 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), combustor replacement, increasing firing temperature and shaft limits, and additional operating mode flexibility. The result of these replacements will be increased capacity and improved heat rate for some operating modes. In addition, the GE 7FA.05 upgrade will give these NGCCs the ability to operate power augmentation (admission of steam to the combustion turbine to increase mass throughput and power output) and peak firing in winter conditions, as well as the ability to operate peak fire and power augmentation simultaneously. 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.
- **Plant McIntosh Units 1A-8A**: The upgrade opportunity being evaluated for Plant McIntosh Units 1A-8A, or the simple cycle CTs, also includes replacing existing turbine components, which will allow each unit to operate at a higher capacity. In addition to increasing capacity, these replacement components are of lower cost than the in-kind replacement parts, leading to a reduction in 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.

The Company has provided a detailed cost-benefit analysis in Technical Appendix Volume 1. This analysis clearly demonstrates that these upgrades are in the best interests of customers. The certification application for this incremental capacity is also included in Attachment B of the Main Document.

8.4 – Nuclear Unit Upgrades

Similar to the gas upgrades discussed in Section 8.3, the Company has identified opportunities to upgrade several of its existing nuclear units to provide additional capacity. This additional baseload energy can aid in meeting growing capacity needs without the need for incremental transmission system investment. Upgrades are proposed for Plant Vogtle Units 1-2 and Plant Hatch Units 1-2.

These Extended Power Uprates ("EPU") result in greater electrical power generation as shown in Table 8.4 by increasing the thermal output of the reactors. The EPU process includes an extensive analysis of plant systems and components to verify the capability and identify needed modifications to support the power upgrade at each facility. For Plant Hatch, the Company is also planning to complete a necessary upgrade to boiler water reactors called the Maximum Extended Load Line Limit (MELLA+) enhancement. The MELLA+ enhancement increases capacity by allowing for higher thermal power without increasing core flow to support EPU for boiling water reactors. In addition to the upgrades described above, the Company is considering an option for Vogtle Units 1-2 that would transition the outage window to a 24-month cycle. This upgrade would extend unit runtimes and decrease the number of refueling outages across the fleet.

Table 8.4: Projected Nuclear Upgrade Schedule (MW)

Calendar Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Vogtle 1*	0	0	0	7	27	27	27	27	27
Vogtle 2*	0	0	7	7	7	27	27	27	27
Hatch 1	0	0	0	0	30	30	30	30	30
Hatch 2	0	0	0	28	28	28	28	28	28
Total (GPC Ownership)	0	0	7	42	92	112	112	112	112

*Delivery dates assume the earliest potential outage windows based on preliminary engineering design

The Company's request to upgrade its nuclear units and unlock additional capacity is supported by an economic analysis that is detailed in Technical Appendix Volume 1, which highlights the cost-effectiveness of the proposed upgrades. The upgrade investments are supported by Federal and State incentives. The IRA-enabled Section 45Y, or PTCs, are substantial for high-capacity factor nuclear units and will provide 10 years of benefit for the upgrade capacity achieved. The state of Georgia offers an ITC for investments in new or existing facilities. The upgrades to Plant Hatch are expected to qualify for 5% and the upgrades to Plant Vogtle are expected to qualify for 3%. The Company assumes these projects will qualify for the Department of Energy ("DOE") Title 17 Loan Guarantee Program that affords additional financial savings.[32] Lastly, the Company is evaluating whether incremental energy gained through the EPU can be offered to interested customers as a part of a carbon-free energy subscription program, decreasing the net cost to non-participating customers, and providing access to incremental clean energy attributes to help meet customer-specific needs.

[32] The Title 17 Clean Energy Financing Program offers borrowers access to (i) a direct loan from U.S. Treasury's Federal Financing Bank backed by a 100% full faith and credit DOE guarantee, or (ii) a DOE partial (up to 90%) guarantee of commercial debt. Specifically, Section 1706 offers financing for Energy Infrastructure Reinvestment projects.

The EPU are a validated proven process that have been implemented at Plant Hatch, Plant Vogtle and by other nuclear electric utility operators. The Company is working with the Nuclear Regulatory Commission ("NRC") as a part of the required review and licensing process. The NRC will review the license amendment request that contains the detailed analysis to support the power upgrades and concur with approval to allow the upgrade of each facility. Pending NRC review and approval, the Company expects to deliver the first phase of unit upgrades by 2028/2029. By investing in these upgrades, the Company is providing customers with economic, carbon-free baseload energy.

8.5 – Wholesale-to-Retail Offer

The Commission's July 30, 2008 Order in Docket No. 26550 requires 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 have been offered under this arrangement and accepted or rejected by the Commission. As additional wholesale contracts expire, the Company evaluates when to offer wholesale capacity blocks to the retail jurisdiction. At the conclusion of the 2022 IRP, 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; however, it also acknowledged that the Company could, at its discretion, offer wholesale capacity back to the retail jurisdiction. Four wholesale blocks associated with Plant Scherer Unit 3 will become available between 2026 and 2032, as shown in Table 8.5 below.

Table 8.5: Plant Scherer Unit 3 Wholesale Capacity

Unit	Wholesale Block	Approximate Capacity (MW)	Date Available to Retail Customers
Plant Scherer Unit 3	EnergyUnited Electric Membership Corporation ("EnergyUnited") Coal Block	52	1/1/2026
Plant Scherer Unit 3	Flint Electric Membership Corporation ("Flint EMC") Steam Block	55	1/1/2030
Plant Scherer Unit 3	Retail – Florida Power & Light ("FPL")	55	1/1/2031
Plant Scherer Unit 3	Retail – Duke Energy Florida ("DEF")	25	6/1/2031

Georgia Power did not offer Plant Scherer Unit 3 capacity from the EnergyUnited Coal Block back to retail jurisdiction in the 2022 IRP due to the then-current request to retire the unit by December 31, 2028. However, since the load forecast and corresponding capacity needs have changed since the 2022 IRP, pending the Commission's decision to extend Plant Scherer Unit 3 in the 2025 IRP, the Company recommends this 52 MW of capacity be returned to the retail jurisdiction. This capacity would help to fulfill a portion of the Company's capacity needs in the near term.

There is additional capacity associated with Plant Scherer Unit 3 that will become available in the early 2030s timeframe. First, approximately 55 MW of wholesale block capacity serves Flint EMC through the end of 2029. Second, approximately 79 MW of formerly wholesale block capacity serves retail customers until 2031. This capacity from Plant Scherer Unit 3 was previously accepted into the retail jurisdiction for a term of fifteen years by Commission Order on September 15, 2009. These wholesale blocks represent a total offering of approximately 187 MW to the retail jurisdiction from Plant Scherer Unit 3.

In prior wholesale capacity offers, the Commission has approved the 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 assumed remaining life, expressed on a dollar per kilowatt-month basis. The Company's offer of the 187 MW of wholesale block capacity utilizes the same MDA construct as previous offers. Because the ultimate outcome of the 111 GHG Rules is subject to legal uncertainty due to ongoing petitions for review, the Company is providing MDA values for both 111-MG0 and MG0 planning scenarios. The Company requests approval for whichever scenario is appropriate based on the status of the 111 GHG Rules at the time the wholesale capacity would be placed in retail service.

If the Commission accepts the Company's offer of approximately 187 MW of wholesale block capacity to retail jurisdiction, the Company requests that the capacity also be certified in this 2025 IRP. Additional information on the offer is found in Technical Appendix Volume 1, and the formal certification application is included in Attachment A of the Main Document.

8.6 – Hydro Modernization

8.6.1 – Continued Investment in the Hydro Fleet

Georgia Power's fleet of hydroelectric generating units is a source of emission-free energy, with some units serving the state of Georgia for over 100 years. The Company operates 15 hydro generation facilities and has an ownership interest in an 16th – Plant Rocky Mountain – with a total of 66 hydroelectric generating units in Georgia. These facilities are all licensed by FERC under the Federal Power Act ("FPA"). In all, Georgia Power has ownership rights to over 1,100 MW of hydroelectric capacity. Details related to the FERC relicensing status and schedule for these hydro generation facilities are included in Attachment F.

Pumped storage hydro facilities, such as Plant Wallace Units 1, 2, 5, and 6, have also reliably served as the original energy storage systems, which continue to be important for the integration of an increasing number of intermittent renewable resources. As described in the 2019 and 2022 IRPs, Georgia Power's hydro generation facilities have essential equipment that has reached or is nearing the end of useful life and require modernization investments to continue their generating capability to maintain compliance with their FERC licenses under the FPA. Hydro modernization projects include critical replacements and/or refurbishments needed for turbines, generators, and balance of plant ("BOP") equipment. These investments will allow these resources to operate for at least another forty years while improving the efficiency and integrity of the hydro fleet and preserving valuable, dispatchable carbon-free resources for the long-term benefit of customers.

Under the FPA, license holders are required to make all necessary replacements to maintain facilities in a condition adequate for the efficient operation in the development and transmission of power.[33] FERC has stated, in an Order approving a license amendment associated with one of the hydro

[33] 16 U.S.C. § 803(c) (2023).

modernization projects previously approved by the Commission, that "given the age of the equipment, if Georgia Power does not conduct the proposed work, the [facility] would be at risk on non-operability and might not be able to be operated safely within the current license requirements. . . . The proposed upgrades would allow Georgia Power to adequately maintain the project and meet the terms of its current license."[34] At sites not yet approved for hydro modernization by the Commission, Georgia Power already has four hydro units on forced outage that will remain inoperable until hydro modernization work is complete. Therefore, approval in this IRP of the hydro modernization projects at the remaining hydro facilities operated by Georgia Power is needed to ensure ongoing compliance with the Company's FERC licenses and the FPA.

It is important to note, for units that have not been completed or approved for modernization, outages and equipment failures remain a heightened risk. The Company will take the steps necessary to maintain these units, which may require individual equipment replacement in lieu of the holistic approach utilized for the hydro modernization projects. Until these units are approved by the Commission for inclusion in the program, managing inefficiencies and maintaining reliability of these units will remain a challenge.

In the following sections, the Company provides an update on the hydro modernization projects approved in the 2019 and 2022 IRP Orders and details the request in this IRP to complete hydro modernization projects for the remaining hydro generation facilities operated by Georgia Power. Additionally, Georgia Power is requesting the authority to develop, own, and operate the increased capacity associated with turbine redevelopment for Goat Rock Units 3-6.

The Supply-Side Stipulation approved in the 2022 IRP Order requires that all future hydro modernization requests include a cost-benefit analysis and economic comparison of the alternatives to modernization. Additionally, this type of analysis is required in the 2025 IRP for the previously approved Plant Burton.[35] These analyses for Plant Burton and the remaining hydro fleet are included in the Hydro Modernization section of Technical Appendix Volume 1.

8.6.2 – Progress Since the 2022 IRP

In the 2019 IRP, the Commission approved five projects in the hydro modernization plan: Plant Terrora; Plant Tugalo; Plant Bartletts Ferry Units 1-4; Plant Nacoochee; and Plant Oliver. In the 2022 IRP, the Commission approved two additional hydro modernization projects at Plants Burton and Sinclair. Since then, the Company has continued making significant progress on these approved projects through the design, engineering, procurement, and construction of this highly specialized 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

[34] Order Amending License, Approving Revised Exhibits A and F, Revising Project Description, and Revising Annual Charges, 182 FERC ⁋ 61,087, at ⁋ 39 (February 16, 2023) (FERC Final Order on Plant Tugalo Amendment).
[35] 2022 IRP Order at 29.

completed for Plant Bartletts Ferry Units 1-4, and construction is currently ongoing at the site, where challenges associated with supply chain issues and identification of more equipment wear and damage than anticipated during the discovery process, are expected to result in overall delays to the project. Engineering and procurement processes are in progress for the remaining plants. The Company has kept the Commission abreast of its progress on these units through its bi-annual reporting in Docket Nos. 42310 and 44160.

For the approved hydro modernization projects, Georgia Power has been selected for approximately $15 million in DOE grant funding related to hydroelectric efficiency improvements and maintaining and enhancing hydroelectricity under the Infrastructure Investment and Jobs Act ("IIJA"), also known as the Bipartisan Infrastructure Law. The full amount of each grant is awarded at the successful completion of the project for all applicable units. The selected projects are Plant Tugalo Units 1-4 Turbine Upgrades ($5 million), Plant Tugalo Generator Upgrades ($5 million), and Plant Bartletts Ferry Units 1-4 Generator Upgrades ($5 million). Georgia Power is pursuing DOE Title 17 loan opportunities that support Energy Infrastructure Reinvestment. The Company also seeks to maximize available IRA and state tax credits in order to pass those benefits through to customers for all ongoing projects. Commission approval of these hydro modernization projects has provided the Company with the certainty needed to begin the work required to apply for this federal funding.

8.6.3 – Next Steps: Remaining Hydro Fleet

As the Company progresses on the currently approved seven projects, it is imperative to continue the hydro modernization efforts on the remaining nine facilities: 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.

Approval to modernize the remaining hydro fleet will allow the Company to fully gain the benefits of enhanced fleet dispatch and operational efficiency of each river chain. The hydro modernization effort seeks to strategically plan projects while optimizing resources, design, planning, and execution of work in a more efficient manner than a longer-term piecemeal approach. Approval of the remaining fleet will allow the Company the flexibility to address the sites with the most pressing need of maintenance to mitigate extended unit outages in the near future, thereby benefiting the overall hydro modernization schedule.

Building on the experience and best practices established through the previously approved seven projects, a coordinated modernization effort for the remaining hydro fleet is necessary to most cost effectively address the challenges at each facility. This approval will also maximize flexibility and efficiency for project implementation related to supply chain, permitting, labor force, and clean energy incentives, such as grant and loan opportunities. Specifically, approval of hydro modernization for the remaining hydro fleet provides an opportunity for the Company to effectively retain and utilize a trained and experienced workforce, improving the Company's ability to successfully modernize its remaining units. The Company's modernization approach for the remaining hydro fleet gives continuity and efficiency of engineering design, minimizes construction mobilization costs at the sites, allows volume procurement, and optimizes the design and selection of equipment.

The Hydro Modernization section of Technical Appendix Volume 1 includes the estimated capital costs for these remaining hydro plants, as well as the required cost-benefit analyses and economic comparisons of alternatives to modernization for the requested sites and Plant Burton and associated supporting materials.

8.6.4 – Plant Goat Rock Units 3-6 Turbine Redevelopment

For Goat Rock Units 3-6, Georgia Power is also requesting authority to develop, own, and operate the capacity increase 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. Actual capacity increases will be dependent on the project design. Following the approval of this request, the Company plans to complete further engineering and procurement processes to determine the optimal technology solution and design for these units. Georgia Power will provide a certification amendment application, including final engineering, procurement, and construction agreements and project cost estimates for Commission approval once finalized.

8.7 – Update on 80 MW Energy Storage Demonstration Projects

In the Commission's 2019 IRP Final Order, the Company was approved to develop 80 MW of energy storage demonstration projects. The 80 MW includes the 65 MW, 4-hour Mossy Branch project that entered commercial operation in October 2024 and an additional 2 MW to be identified as distribution-interconnected BESS, as well as a potential 13 MW, 4-hour BESS project at Fort Stewart Army Base in Liberty County, Georgia.

For the Fort Stewart project, Georgia Power is currently engaged in contract negotiations with the installation contractor and battery integrator, and the Company is in active discussions with the Army regarding the potential to develop, own, and operate storage capacity at Fort Stewart. Georgia Power coordinated with the Army to develop a proposal to address national security requirements related to equipment sourcing, and the Company is currently on hold pending confirmation from the Army of the compliance of the proposed plan before progressing with any identified BESS projects at Fort Stewart.

In accordance with the 2019 IRP Order, once discussions are complete with the Army and agreements are finalized, the Company will submit a plan through a compliance filing with the Commission before undertaking construction and procurement of this project. In addition to the 13 MW, the Company has identified the opportunity to add an incremental 30 MW of 4-hour BESS resources at the Fort Stewart site. As discussions progress further, the Company will return to the Commission with any specific request regarding this incremental 30 MW BESS addition.

8.8 – Blackstart Units

As a part of the 2022 IRP, the Company highlighted its commitment to delivering a robust and resilient electric system on behalf of customers. Over the last decade, the evolving characteristics of the generation fleet, including changes to the fuel mix, penetration of renewable resources and unit retirements, have created uncertainty in the capabilities of its blackstart resource plans. As such, Georgia Power partnered with the Electric Power Research Institute ("EPRI") to conduct a study that evaluates the effectiveness of existing restoration units and potential enhancements from unit additions.

EPRI's study of Georgia Power's blackstart resources concluded that the Company's existing assets and restoration plans are robust and capable of restoring the Georgia Power System during a blackout event. The study makes assumptions on the shortest transmission path from blackstart resources to critical loads to quantify the time required to restore existing customers in each of Georgia Power's islanding schemes. The study also offers various suggestions on ways the Company can fully utilize existing resources and add additional resources to optimize or reduce restoration times for critical loads on the System.

Further details are provided in the Selected Supporting Information section of Technical Appendix Volume 2. As aging units are replaced with new technologies and new load is added to the System, Georgia Power will continue to evaluate the capabilities of its blackstart restoration plans, balancing resiliency of the System with affordability for its customers.

8.9 – Resource Mix Study

The Company's expansion planning analysis identifies the economically optimal mix of resources that meets future capacity and energy demands reliably. 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. Importantly, generic expansion plans do not represent a resource planning decision by the Company, but rather, are indicative of what may be an economically optimal mix of resources within various scenarios.

As such, the purpose of the expansion planning process is to evaluate capacity and energy resource options to meet the capacity need across a wide range of potential future scenarios. To develop the expansion plan, the generation technologies that pass detailed screening are further evaluated using the Aurora capacity expansion and production cost model, which is widely used throughout the electric industry. Aurora employs a generation mix optimization module that includes the following major inputs: (1) load forecast; (2) existing, planned, and committed resources; (3) fuel prices; (4) emission costs; (5) future generating unit characteristics, capital cost, and availability; (6) the capital recovery rates necessary to recover investment cost; (7) capital cost escalation rates; and (8) a discount rate. The Aurora model considers all possible combinations of capacity additions, on a yearly basis, that satisfy the Company's target reserve margin and build constraints. For each scenario evaluated, the resulting combination of candidate resources with the smallest production and capital cost over the planning horizon (in net present value ("NPV") terms) represents the least-cost plan.

The Resource Mix Study in Technical Appendix Volume 2 provides a detailed technical review of the expansion planning analysis and its results.

8.9.1 – Summary of Inputs & Assumptions

The expansion planning process incorporates a wide range of inputs and assumptions, including, but not limited to, reliability criteria, load and energy forecasts, and numerous key financial and economic scenarios.

Reserve Margin

The 2025 IRP includes a 20% Summer Target Reserve Margin and a 26% Winter Target Reserve Margin for the System for long-term resource planning decisions. Chapter 6 and the Reserve Margin Study in Technical Appendix Volume 1 provide additional information on the Company's Target Reserve Margin assumptions.

Economic Forecast

S&P Global's macroeconomic forecast serves as the basis for inflation and cost of capital estimates. S&P Global developed a forecast of economic variables and demographic statistics for the state of Georgia. Key descriptive variables from the economic and demographic forecast for Georgia were used to produce the B2025 Load and Energy Forecast.

Load and Energy Forecasts

The B2025 Load and Energy Forecast discussed in Chapter 5 was utilized for the Company's 2025 IRP Resource Mix Study. The load and energy forecasting process uses a combination of end-use and econometric analyses and is explained in detail in Chapter 5 and in Technical Appendix Volume 2. Certain load forecast scenarios are also discussed in Chapter 3.

Fuel and Carbon Views

The 2025 IRP Resource Mix study incorporates the fuel and carbon views described in Chapter 3.

Financial Cost and Escalation

The Company assumes that long-term debt and common stock are issued to finance the construction of generating units. These financing costs, along with the associated income tax rates, affect the carrying cost of the investment, which can in turn affect the resource capacity mix.

The S&P Global forecast is the basis of the financing and inflation cost estimates used in the planning process. Discount analysis using the weighted average cost of capital is applied to place more emphasis on the near term. More information on the discount analysis and the financial parameters used in the mix process is shown in the Resource Mix Study in Technical Appendix Volume 2.

8.9.2 – Technology Screening

The Company performs detailed expansion planning and production cost analysis during each IRP. This detailed analysis requires extensive and complex computational analysis. Therefore, the Company completes a technology screening assessment of new generation technologies to reduce the potential list of new supply-side options to a manageable list of technologies that are likely to be economically competitive. This technology screening assessment evaluates both established and emerging generating technologies. The objective is to assess the cost, maturity, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other relevant factors of new supply-side generation options.

The technology screening process includes three main steps: (i) the Technology Identification; (ii) Preliminary Screening; and (iii) Detailed Qualitative Screening Analysis, as illustrated in Figure 8.9A. Supply-side options retained after these steps are then considered in the more detailed expansion plan modeling. The Technology Screening process is further reviewed in Technical Appendix Volume 2.

Figure 8.9A: Technology Screening Process

8.9.3 – Expansion Plan Candidate Resources

Electricity generating technology is always evolving. Therefore, as discussed previously, the Company's screening process identifies those technologies that have the greatest possibility of playing a cost-effective role in the System during the modeling horizon. Even among the technologies that might play such a cost-effective role, there remains uncertainty about the cost of each technology relative to its expected productivity and other technology options.

For B2025 analyses, the technologies that passed initial screening, indicating their potential cost-effectiveness, include NGCC, dual-fuel CT with SCR (oil-fueled in winter), solar PV, wind, nuclear (AP-1000), lithium-ion battery storage, and compressed air or pumped thermal energy storage. In addition, NGCC with CCS passed initial screening based on an assumed trajectory of technology and infrastructure development towards future commercial availability. While this trajectory and the ultimate costs remain highly uncertain, the inclusion of NGCC with CCS allows the Company to evaluate scenarios for this potential future resource option. Table 8.9A provides key modeling assumptions and limits for each of these candidate technologies. Note that for certain technologies, such as NGCC with CCS, there may be additional infrastructure or technology limitations that are not yet well understood at this time and are not captured in the model.

Table 8.9A – Candidate Technology Assumptions

Candidate Technology	First Year Available	Last Year Available	Modeling Limits
Combined Cycle (1x1)	2029	• 111: available through planning horizon; limited to 40% capacity factor beginning 2032 • *Lower* CO_2: 2039 • *Moderate*, *Higher*, & *EL* CO_2: 2036	• Market options (2029 limited to 900 MW) • Natural Gas Firm Transportation availability (FT availability)
Combined Cycle with CCS (Local)	2037	• Available through planning horizon	• FT availability • Geology
Combined Cycle with CCS (Distant)	2037	• Available through planning horizon	• FT availability
Combustion Turbine with SCR	2029	• Available through planning horizon	• Oil operation in winter months (January, February, and December) • 20% capacity factor annually
Solar PV	2028	• Available through planning horizon	• 1,500 MW / year
Wind	2033	• Available through planning horizon	• 300 MW / year • 4,500 MW total
Short Duration Energy Storage (4-hour)	2028	• Available through planning horizon	• 3,000 MW / year
Medium Duration Energy Storage (12-hour)	2033	• Available through planning horizon	• 3,000 MW / year
Nuclear (AP-1000)	2037	• Available through planning horizon	• 600 MW / year

The cost estimates for each of the natural gas, storage, solar, wind, and nuclear technology options were developed based on proprietary sources of information. Current estimates for costs, spending curves, emissions, and operating characteristics for these resources are contained in the Technology Screening and Applications Standards in Technical Appendix Volume 2.

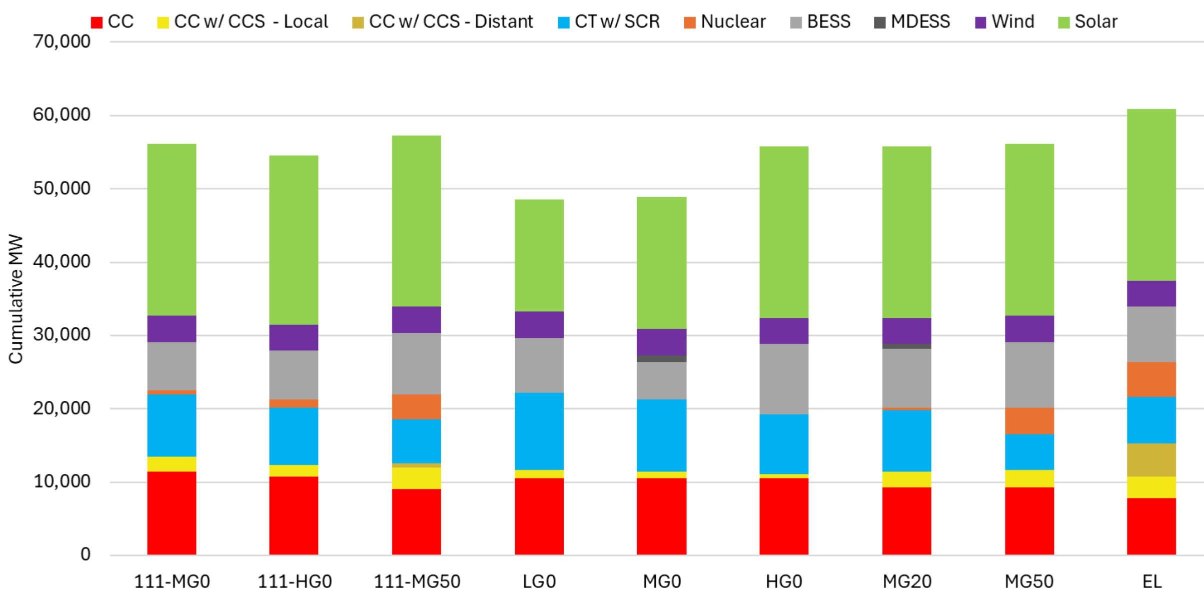
8.9.4 – Modeling Results

The expansion planning analysis in the Resource Mix Study maintains the Company's Target Reserve Margins while considering a wide range of possible future scenarios. The results of the expansion planning analysis ensure the Company is evaluating a range of economic conditions that may differ materially from current economic conditions. This process ensures the Company is making decisions with the best available information, while appropriately considering the risk associated with long-term resource planning decisions in the best interest of customers. The outcome of this method is a cost-effective mix of demand-side and supply-side resources that inform the Company's long-term avoided costs. When Georgia Power acquires resources to meet capacity needs identified in the IRP, the actual generation resource procured will be selected in accordance with the Commission's RFP rules.

The long-term expansion plan for each of the scenario cases, which is further described in Chapter 3, varies depending on the assumptions for that case. A mix of CTs, CCs, nuclear, renewable technologies (solar and wind), and storage was selected for the scenario cases through the planning period when resources were needed to maintain reliability, meet growing customer needs, or provide fuel-cost savings. Generic expansion plans for the nine scenarios are summarized in Figure 8.9B. The generic expansion plans identify the resource mix that is most economical for customers in each scenario.

Figure 8.9B shows the cumulative expansion plans for the System over the 20-year planning period. The results show that CT and CC resources, in addition to battery storage, are added across all scenarios to help fulfill the capacity need. Nuclear shows up in all the scenarios that include GHG pressure, including all the 111 GHG Rules scenarios. All scenarios show substantial additions of solar and wind resources to be cost effective through the planning period.

Figure 8.9B: B2025 Generic Expansion Plan Results (2025-2044)



These generic expansion plans are combined with the existing fleet of resources as inputs into more detailed production cost modeling to produce hourly forecasted marginal energy costs for each scenario. Please refer to the Resource Mix Study in Technical Appendix Volume 2 for more information on the generic expansion plan.

8.9.5 – Sensitivities

The planning scenarios and sensitivity analyses combine to provide a robust view of potential future outcomes that inform the Company's decision-making. Table 8.9B summarizes sensitivities to the

111-MG0 and MG0 scenarios, which were performed in accordance with Commission rules[36] and analyzed in detail in the Resource Mix Study and Financial Review, each found in Technical Appendix Volume 2.

Table 8.9B: IRP Sensitivity Summary

	Required Analysis	Applicable Sensitivities
1	Forecast of load	The Company considers a range of load forecasts in Sensitivities 0-10.
2	In-service dates of supply and demand resources	Sensitivities 0-9 evaluate the impacts of varying in-service dates and amounts of supply and demand resources through the scenario planning cases. These sensitivities produce separate evaluations of the impacts on the load and energy forecasts, which include effects from demand-side programs and new supply-side resources. Sensitivities 10 and 11 evaluate differing levels of demand-side programs.
3	Unit availability	Sensitivities 0-11 evaluate the impacts of varying in-service dates and amounts of supply and demand resources through the scenario planning cases. Additionally, the Reserve Margin Study evaluates unit outages.
4	Fuel prices	Sensitivities 0-8 evaluate the impacts of fuel prices through the scenario planning cases which have three separate fuel price environments and resulting forecasts combined with varying estimates of carbon prices.
5	Inflation in plant construction costs and costs of capital	Sensitivities 0-11 evaluate higher and lower costs of carbon-free technologies by varying the phase out year for the IRA. These alternative costs can be representative of inflation in plant construction costs and cost of capital.
6	Availability and costs of purchased power	Sensitivity 12 evaluates the impacts of differing availability and cost of purchased power.
7	Pending federal or state legislation or regulation	Sensitivities 0-8 evaluate the impact of pending legislation or regulation through the scenario planning cases. The impacts of pending legislation or regulation can be analyzed by varying estimates of carbon and fuel prices.
8	Rate Impact Analysis	All of the sensitivities analyze the impacts on rates of the varying changes in assumptions. The rate impacts are included in the Financial Review in Technical Appendix Volume 2.

[36] See Georgia Public Service Commission Rule 515-3-4-.05(1)(d) for sensitivity requirements.

8.10 – Capacity Procurement

As required by the Commission's IRP Rules and to ensure customers receive reliable capacity and energy at competitive market rates, the Company utilizes an RFP process to satisfy its capacity needs. Active capacity RFPs previously approved by this Commission from the 2022 IRP and the 2023 IRP Update, such as the All-Source Capacity RFP for 2029-2031 and the Winter 2027/2028 BESS RFP, are intended to meet the Company's capacity needs through the winter of 2030/2031. The Company is evaluating the results of the Winter 2027/2028 BESS RFP and the All-Source Capacity RFP for 2029-2031 as well as investigating additional resource options to meet customer needs should these RFPs be insufficient to fill all capacity needs for this period. 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 to be procured through this RFP will be determined based on the Company's capacity needs at the time of RFP issuance, which will be informed by the outcome of this 2025 IRP and the results of the Company's active capacity RFPs. 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.

8.11 – Renewable Procurement

Georgia Power, the Commission, and renewable energy stakeholders in Georgia have created a vibrant, sustainable renewable energy market that continues to benefit all Georgians. This success can be measured not only by the number of projects and renewable capacity on the System, but also by the value created for customers through the Company's robust renewable planning and competitive procurement processes. In the 2025 IRP, the Company proposes to continue capturing benefits for customers through renewable procurements, improving processes and flexibility to create efficiency, and to evolve procurement strategy to meet the needs of individual customers with sustainability goals, while also generating the most benefit for all Georgia Power customers.

Through the leadership of the Commission, Georgia Power creates value by adding renewable energy resources at prices that lower costs for all Georgia Power customers. This forward-thinking policy to add energy-benefiting resources through competitive procurements, while minimizing-any upward pressure on rates, has created a sustainable renewable ecosystem that delivers benefits to customers. With the 2025 IRP, the Company is seeking approval of the following renewable procurement process enhancements, as detailed further in this section.

- *Utility Scale RFPs:*
    - Approval to issue the 2026 US RFP seeking to procure energy from 1,000 MW of US resources, with enhancements including flexible Commercial Operation Dates ("CODs"), and two additional procurement opportunities as part of the RFP.
    - Continue the best-cost evaluation methodology for selecting both standalone renewable resources and those paired with storage.
    - Introduce new processes including the "buy down" option and extended RFP periods with a goal to maximize project selection and procurement.

- *Distributed Generation RFPs:*
    - Approval to issue the 2026 and 2027 DG RFPs targeting 100 MW (50 MW each), including an additional procurement opportunity as part of each RFP.
    - Continue the best-cost evaluation methodology and locational guidance.
    - Introduce new processes such as the "buy down" option and extended RFP periods with a goal to maximize project selection and procurement.
    - Expand DG procurements to seek flexible resources that include dispatchable storage and updated locational value assessments.
    - Require visibility and control of new renewable resources through integration with DERMS.

Through market interaction and recent experience procuring renewable resources, the Company has identified challenges and opportunities that inform its renewable strategy and necessitate modifications to its procurement plans. These proposed enhancements reflect Georgia Power's commitment to adapting strategies to market conditions and technological advancements, ensuring a sustainable energy future for Georgia.

8.11.1 – Growing Renewable Energy Needs

The need to add significant amounts of renewable resources to the System is based on two fundamental drivers:

- Planning model results which indicate that the addition of cost-effective renewable energy to the System will provide value to all Georgia Power customers through a diverse energy mix; and
- Growing needs of new and existing customers with sustainability/carbon goals, who depend on new renewable energy resources to lower carbon in the overall System mix and provide subscription opportunities.

8.11.2 – Dynamic Procurement Challenges

Through extensive experience conducting multiple renewable procurements, the Company is aware of multiple dynamic challenges that dictate the need for enhancements to RFP processes to improve the likelihood of success through Commission-approved procurements. Transmission system capacity, changing interconnection processes and requirements, uncertain policy impacts (tariffs, tax credits, grants etc.), increasing scrutiny on land use, and supply chain challenges are among the reasons renewable solicitations must become more flexible and adaptable to capture the value that renewable resources can offer to customers. In response to these challenges, and in light of the continuing need to add cost effective renewable resources to the System, the Company is proposing several significant enhancements to processes aimed at improving the efficiency and success of its renewable procurements.

8.11.3 – Utility Scale RFPs

Utility Scale RFP Results

The 2022/2023 Utility Scale RFP resulted in the certification of five PPAs representing 970 MW. One project subsequently withdrew, leaving four projects totaling 750 MW. Three of these projects reached COD in November 2024. The fourth project is expected to reach COD in 2025. During this RFP, the Company identified several market challenges and worked with the Independent Evaluator ("IE") and Commission Staff to address market conditions and feedback from bidders, by making modifications including an extension to the Required Commercial Operation Date ("RCOD"), which provided flexibility needed to navigate policy and supply chain dynamics. These changes ultimately allowed four of the five projects to remain viable and reach commercial operation, while one project defaulted and did not move forward. MW left unfilled from this RFP rolled forward into the MW target for the 2023/2024 Utility Scale RFP, and Customer Renewable Supply Program ("CRSP") customer subscription needs were addressed on a pro-rata basis through the remaining PPAs. The Company gathered significant insights into market challenges through this process, including supply chain, changing public policy, land use issues, and transmission system access, and has incorporated these learnings into its plans for future procurements.

Due to challenging market conditions, the 2023/2024 Utility Scale RFP did not yield any bids that met the RFP criteria as evaluated by the Company, the Independent Evaluator, and Commission Staff. The Company considered potential modifications but ultimately determined that none of the bids could produce benefits for Georgia Power customers. The Company worked closely with the market participants, Staff, and the IE to evaluate the outcome of this RFP and has applied the information it learned to enhance future procurements. The MW not procured in the 2023/2024 RFP were rolled forward to the procurement targets for the 2023 CARES Utility Scale RFP.

The 2023 CARES Utility Scale RFP, which is currently underway, seeks a procurement target of up to 2,875 MW, which includes the MW rolled over from prior RFPs. Based on market feedback, the RFP was modified to allow for RCODs as late as 2029, and now includes a bid refresh process to facilitate this change. Additionally, the Company requested an extension to the announcement of bids in the short list, which provides additional time to evaluate bids to most effectively add new, reliable, clean energy resources. Georgia Power expects to announce the results of this RFP in Q1 2025.

The Company plans to issue the 2025 CARES Utility Scale RFP in Q2 2025 with a target procurement of 475 MW, plus any MW that are rolled forward from the 2023 CARES Utility Scale RFP.

Utility Scale RFP Procurement Strategy

In this IRP, the Company proposes a modified RFP strategy that applies valuable information learned in implementing recent Utility Scale RFPs and builds on the historical success of renewable energy RFPs to the benefit of customers. The Company proposes to continue utilizing a best-cost evaluation methodology to select renewable resources and renewable resources paired with renewable or grid-charged storage systems. The Company also proposes modifying the RFP structure and cadence to create additional opportunities for bidders and customers to identify resources for procurement. The Company proposes to modify the Utility Scale procurement process by adding flexible CODs, and to offer two additional opportunities for procurement as part of the RFP. The Company will seek to procure energy from a target amount of 1,000 MW for all customers in the RFP, with the ability to procure energy from up to an additional 3,000 MW to meet customer subscription demand. This strategy promotes flexibility and optionality and offers the ability for both bidders and potential subscribers to contribute to the cost effectiveness of individual projects and allow for the selection of additional PPAs beyond initial procurement targets, as appropriate.

Specifically, the Company is proposing the following enhancements to its utility scale procurements:

- *Phase I – traditional RFP with added buy down option*

  To provide the ability for more projects to be procured in Utility Scale RFPs, the Company proposes extending the RFP process to allow for additional bids to be selected. To address customer subscription needs remaining after the Company identifies the short list in the RFP, the Company may implement a bidder "buy down" process, where projects in the competitive tier — but not selected for the short list —will have the option to buy-down the bid price to meet the average Total Net Benefits of bids in the selected portfolio. This process will be designed in compliance with Commission rules to ensure additional bids selected meet the Commission's certification requirements.

- *Phase II – Extended RFP Period (Customer Identified Resource ("CIR") Process)*

  The Company proposes to add a second phase of the Utility Scale RFP process, which would keep the RFP active and allow new projects to be submitted at or below a price that results in a Total Net Benefit that equals the average Total Net Benefit from the initial procurement phase. This second phase would offer additional customer subscription opportunities while securing additional renewable resources in a manner that preserves benefits and maintains protections for all Georgia Power customers.

  The second phase would only be made available if necessary to address unmet CARES Utility Scale customer subscription needs. Project developers and potential subscribers could work together to submit bids into two additional submission windows priced at or below a target deemed competitive with the original portfolio Total Net Benefits, with final pricing determined after comprehensive bid and Transmission analysis. Additionally, bidders could submit new bids in this extended RFP process independently, with the Company offering additional subscription opportunities from incremental projects to potential CARES subscribers, at subscription prices and terms that protect non-participants. Additional details regarding the enhanced subscription process can be found in Chapter 10.

8.11.4 – Distributed Generation RFPs

2023 & 2024 DG RFP Results

In the 2022 IRP, the Commission approved two distributed generation renewable RFPs, the 2023 DG RFP and the 2024 DG RFP, which sought to procure energy from 293 MW of solar resources (which included 93 MW rolled over from the 2020 DG RFP). Conducting two consecutive RFPs in a three-year cycle enabled a large number of bids to be evaluated in a more timely and efficient process. The 2023 and 2024 DG RFPs also sought to procure energy from solar facilities sized up to 6 MW AC, which was an increase from the size limit of 3 MW AC in prior RFPs.

Prior to the issuance of these DG RFPs, bidders were provided access to additional tools to support DG RFP bidding, including the locational guidance process, an RFP enhancement approved in the 2022 IRP Order that includes a hosting capacity map for bidders. This enhancement, coupled with the Company's Interconnection Guidance process, added significant efficiency to the RFP process by helping bidders locate projects in more favorable locations. Bids were evaluated using the best-cost methodology, approved in the 2022 IRP Order, which enables procurement of renewable resources at the best cost for Georgia Power customers. These process improvements contributed to a higher percentage of bids progressing to the Target List, on average, than in previous RFPs.

Through December 31, 2024, Georgia Power executed 12 PPAs for 41.83 MW of solar resources in the 2023 DG RFP, and the projects are expected to reach Mechanical Completion in 2025. The 2024 DG RFP is ongoing and has been well received by the marketplace. Results will be made available in late 2025. Similar to the Utility Scale RFP process, the success realized through changes already implemented, combined with continuous learning gained from conducting these RFPs, informs the proposed enhancements for future distributed generation procurements, as detailed below.

Distributed Generation RFP Procurement Strategy

Building upon the success of the RFP enhancements implemented pursuant to the 2022 IRP, the Company proposes to continue utilizing the best cost methodology, locational guidance, and the practice of running two RFPs per three-year IRP cycle. The Company seeks to procure energy from 100 MW of DG resources, through two 50 MW solicitations in 2026 and 2027, respectively, with the ability to procure additional resources to meet customer subscription demand from the CARES DG Subscription Program, further described in Chapter 10. This plan not only supports the Company's long-term renewable integration strategy but is also supported by external stakeholders (i.e., bidders, customers, and installers), as confirmed through ongoing and robust market feedback.

Additionally, the Company received feedback regarding potential enhancements to DG procurements, including process improvements, the options to include BESS as part of the procurement, and potential for offering customer subscriptions to the energy procured through these solicitations. The Company is proposing the following RFP enhancements based on that feedback.

Flexible DG Resources with BESS

With increasing solar penetration, operational flexibility and control at the distribution level is vital to ensure the reliability of the System. Additionally, development of projects in close proximity to each other has created siting challenges on the distribution grid. To continue supporting the growth of renewables that benefit Georgia Power customers, the ability to add solar charged or grid charged dispatchable storage to DG solar facilities will enhance capacity value and allow the storage of excess solar generation. As such, the Company proposes to procure flexible DG resources, with the option to co-locate distribution-connected BESS resources. For operational flexibility, the Company will require visibility and control of new renewable and BESS resources to protect the reliability of the electric system through integration with DERMS. In turn, flexible DG resources will be recognized for the additional System value as part of the RFP evaluation process.

DG Procurement Enhancements

- **Locational Value**. To aid in the development of renewable DG resources in areas with more favorable interconnection conditions, the Company seeks to update the RCB Framework used in the evaluation process to assign value to projects based on their geographic location. Details about this change are further outlined in Technical Appendix Volume 2. In summary, the deferred transmission investment component of the RCB Framework, which is applied to all resources regardless of location, will be replaced with a geographically differentiated transmission system cost benefit factor in the evaluation process to ensure the portfolio of resources selected provides the maximum benefits to Georgia Power customers.
- **Buy-down Optionality and Extended RFP Period**. To further increase the chances of capturing the benefits of cost-effective renewable energy in DG RFPs, the Company proposes modifying the RFP process, in accordance with the IRP statute and Commission rules, to provide additional opportunities for bids to be considered for procurement at the best cost to customers. The first proposed modification to the existing process is similar to the Utility Scale "buy down" process described above, whereby bidders in the RFP that were not selected for the Target List would be provided an option to buy-down the price of the bid to meet the average Total Net Benefits of the selected portfolio. This buy down process would only be implemented if there is an unmet need to supply the CARES DG subscription program.

  The second enhancement is a proposed extended phase of the RFP, which would allow new projects, including customer identified resources, to be submitted into the RFP at, or below, a price that results in a Total Net Benefit for the additional bid(s) that matches the average Total Net Benefits from the first phase of the RFP. This additional option would be available if there continued to be an unmet CARES DG customer subscription need after the first phase of the RFP, including the need to supply the Residential Distributed Generation Community Solar Program. The options through which customers and developers can partner to bring forth those projects are detailed further in the customer programs section. The intent of this multi-phase approach is to provide additional price and demand certainty for developers, and additional subscription opportunities for customers, while preserving benefits and maintaining protections for all Georgia Power customers.

In sum, these changes to the Utility Scale and DG procurement processes are proposed after considerable and serious deliberation in light of recent RFP results, as well as direct feedback from customers and stakeholders. The Company takes pride in conducting industry-leading renewable solicitations aimed at securing renewable resources that create value for customers and is compelled to propose these changes as it seeks to continue efficient and compliant procurements on behalf of all Georgia Power customers and renewable program subscribers. These proposed modifications will be reflected in future RFP and PPA documents, and subject to comment, modification, and approval through the Commission-approved RFP process. The Company remains committed to compliance with appliable statutes, rules, and a desire to meet market and customer expectations, resulting in disciplined and principled procurements that benefit all customers. This continuous evolution of Utility Scale and DG procurements seeks to produce a market and customer-driven process designed to take advantage of changing conditions and technological advances to deliver maximum customer benefits.

8.12 – Nuclear

With Plant Vogtle Units 3-4 achieving commercial operation on July 31, 2023, and April 29, 2024, respectively, Georgia Power completed the nation's first new nuclear generation units in over 30 years. Through the vision and support of the Commission, the Company's leadership, and dedication of over 9,000 workers and 30 million manhours, Plant Vogtle Units 3-4 are delivering over 2,200 MW of clean, safe, reliable, and affordable baseload generation to a growing Georgia. With the addition of Units 3-4, Plant Vogtle is now the largest generator of clean energy in the U.S.

The Company believes that additional nuclear power will be needed over the long-term to reliably and economically serve the energy needs of its customers. Nuclear plants provide resilient baseload power, ensuring a consistent and dependable energy supply without relying on just-in-time fuel deliveries. The fuel costs of operating a nuclear unit are relatively low compared to other energy sources, making it a cost-effective solution over the long term, especially considering the long asset life of a nuclear unit of 60 to 80 years. This benefits the fuel diversity of the generation fleet and plays a significant role in stabilizing fuel prices and dampening the risk of price fluctuations.

Similarly, nuclear power provides a long-term pathway to reduce carbon emissions and mitigate the cost pressures that potential future environmental regulations could impose on the existing fossil-fired fleet and future new fossil resources. Environmental regulation, like the 111 GHG Rules, can impact fossil-fired generation operations and economic benefit through added costs or production limits. In some cases, these cost pressures can drive unit retirements when other generation types or fuels become better options. To that extent, nuclear generation is a viable long-term replacement to fossil-fired baseload resources as it hedges regulatory risk and positions the Company for a low-carbon emissions future.

As discussed in Chapter 3, the Company develops multiple views of future cost and performance of generating technologies, multiple views of future electricity consumption, and multiple views of the future price of fuels to support expansion planning for future years of need. Accordingly, B2025 scenarios select nuclear generation in six of nine scenarios over the 20-year planning horizon and as early as 2037. Carbon pressure, natural gas firm transportation, and carbon capture and sequestration constraints are considerations in the amount of potential nuclear generation that could be economically beneficial for customers.

Even with new nuclear generation's numerous benefits, undertaking the construction of new nuclear generation carries substantial risks for all stakeholders involved. Before proposing additional new nuclear generation, the Company believes that solutions must be developed to adequately balance and mitigate risks to stakeholders. The risks and challenges to the development of new nuclear projects are well known and documented and include the large initial investment, construction cost and schedule risks, as well as the substantial credit quality impacts to the sponsors of the project. The Company's experience completing Vogtle Units 3-4 positions the Company well to be actively engaged with state, local, federal, and customer stakeholders in efforts to address risks associated with new nuclear construction.

Preserving viable new nuclear generation options for the benefit of customers is a priority for the Company. Accordingly, the Company continues to perform in-depth assessments of potential project sites, evaluate available and emerging technologies, and engage with stakeholders in developing improved methods to deploy new nuclear generation projects. Over the long term, with adequate additional risk mitigations and leveraging the experience gained with Vogtle Units 3-4, the Company believes customers would benefit from additional new nuclear in the future.

Chapter 9. Environmental Compliance Strategy & Climate Approach

The 2025 IRP considers changes to federal and state environmental regulatory requirements, and the uncertainty associated with these changes, to develop a flexible and adaptive strategy to ensure continued compliance and resource planning optionality. Recent changes in federal environmental mandates applicable to the utility sector, such as 111 GHG Rules and Supplemental ELG Rule, add significant compliance costs on top of investments and compliance projects that are already in progress, and create constraints on new and existing power plants that present significant resource planning challenges. While these environmental rules are currently being litigated, they remain in effect and carry compliance deadlines that require work to begin immediately. The Company must continue to evaluate and pursue the compliance pathways to meet the existing rules' requirements and do so in a way that is in the best interests of customers and minimizes impacts to both reliability and affordability. The Company's compliance strategy ensures environmental mandates can be met while remaining ready to adapt to future litigation or regulatory developments. 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.

In addition to the constraints imposed by new regulatory requirements, certain climate policies and evolving customer needs also present potential opportunities that are important to consider in the Company's overall environmental strategy. Recent legislation, such as the IRA and IIJA, provide opportunities to increase the affordability of clean energy solutions. Notably, a contributing factor to increased energy needs is the continued electrification of the economy, as customers transition to low-carbon electric solutions, such as electric transportation and electric boilers, rather than traditional fuel-burning technologies. The utility industry is also experiencing extraordinary growth in electricity demand driven by the manufacturing and infrastructure that support these low-carbon technology advancements, including economic development associated with data centers and EVs, battery, and solar panel manufacturing. The IRP framework provides Georgia Power and the Commission with a constructive platform to address these issues—both as constraints and opportunities—in order to reduce carbon emissions risk for the benefit of customers.

This Chapter summarizes Georgia Power's Environmental Compliance Strategy and climate approach, the progress and path forward using resource-planning drivers, and potential long-term technology evaluation and development needed to continue to make cost-effective resource planning and environmental compliance decisions for customers.

9.1 – Environmental Compliance Strategy

Georgia Power has a long history of demonstrating environmental stewardship while meeting the energy needs of customers. Complying with federal and state environmental requirements is a fundamental element of the Company's longstanding commitment to meeting customer energy needs. Consistent with the Company's efforts to supply clean, safe, reliable, and affordable electric service, the ECS describes the comprehensive strategy to comply with environmental laws and regulations through the implementation of cost-effective environmental controls and actions.

The 2025 ECS sets forth the Company's strategy to comply with federal and state environmental requirements, including rules finalized by EPA in the spring of 2024 that impose new requirements on the power sector, such as the 111 GHG Rules and Supplemental ELG Rule. Although the ultimate outcome of these rules is subject to ongoing litigation and there may be future rule revisions, the Company must evaluate compliance pathways and develop a flexible and adaptive strategy to ensure continued compliance and resource planning optionality.

- **EPA's 111 GHG Rules** require new natural gas combined-cycle units to either install and operate CCS by January 1, 2032, or operate to less than 40% annual capacity factor. These stringent requirements would apply to any proposed new natural gas combined-cycle capacity, whether Company-owned or acquired through PPAs, that commence construction after May 23, 2023. The 111 GHG Rules set guidelines for states to require standards for existing fossil fuel-fired steam units through state plans that are due by May 2026. Plant Bowen and Plant Scherer are expected to be subject to standards in a state plan to be determined by Georgia Environmental Protection Division ("EPD") based on three compliance pathways outlined by EPA:

  (1) retirement by January 1, 2032

  (2) installation and operation of CCS by January 1, 2032; or

  (3) 40% co-fire of natural gas by January 1, 2030, and retirement by January 1, 2039.

  Georgia EPD may deviate from these guidelines, including by setting different standards using different timelines, or by considering the remaining useful life and other factors for each coal unit. EPA also provides regulatory mechanisms for a one-year compliance extension if certain conditions are met. Although all compliance options for coal under the 111 GHG Rules are extremely impactful, the natural gas co-fire pathway is the most balanced option of the three. Retirement by January 1, 2032, for these units is not practicable due to reliability and projected capacity needs, and the implementation of CCS is also infeasible due to (1) the required compliance timelines specified and (2) infrastructure and other significant challenges that remain unsolved.

  As a part of Georgia Power's ECS, the 111 GHG Rule 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 as quickly as possible. Georgia Power will also engage with Georgia EPD and other stakeholders on the 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 and reliability in the event the rules are upheld.

- **EPA's Supplemental ELG Rule** requires the installation of additional wastewater treatment controls at current and former coal-fired power plants, even though implementation of the requirements for the 2020 ELG Rule is still in progress. For Plant Bowen, the physical-chemical-biological scrubber wastewater treatment system being installed to meet the 2020

Rule requirements is expected to be complete this year to meet the December 31, 2025, deadline. The Supplemental ELG Rule will require that Plant Bowen install additional controls to meet a zero liquid discharge requirement by December 31, 2029, for both scrubber wastewater and leachate collected from on-site landfills containing CCR. For Plant Scherer, the membrane scrubber wastewater treatment being installed to meet the 2020 Rule by December 31, 2028, is unaffected by the Supplemental ELG Rule, but combustion residual leachate will have to meet new zero liquid discharge requirements. As part of Georgia Power's ECS, the ELG strategy for Plant Bowen and Plant Scherer is to pursue additional controls necessary to meet zero liquid discharge requirements. In addition, ash pond dewatering at current and former coal-fired power plants are subject to potential requirements as determined by the state permitting authority and leachate collected from coal ash landfills at former coal-fired power plants are expected to require physical-chemical treatment.

Georgia Power is continuing to implement the CCR strategy to permanently close CCR ash ponds and landfills. The Company's CCR strategy, approved in the 2019 IRP and again in 2022, continues to be effectively implemented with significant progress made over the last three years. The Company will continue to evaluate opportunities to refine and optimize its closure plans. Also finalized in 2024, EPA's CCR Legacy Rule establishes two new categories of federally regulated CCR units. Therefore, Georgia Power must complete required facility evaluations at all 12 current and former coal generation locations. The Company expects limited impact to Georgia Power CCR units under the new definitions because those units have already been regulated under similar state requirements. The finalization of the federal rule, however, subjects these legacy units to duplicative requirements and oversight by both the state and federal agencies. Georgia Power's ECS for the CCR Legacy Rule includes completing the required site investigations that began in late 2024, as well as complying with administrative applicability reports and website updates.

The ECS also discusses various other key environmental rules that continue to evolve, such as the Mercury and Air Toxics Standards ("MATS") Rule revision applicable to Plant Bowen and Plant Scherer requiring continuous emissions monitoring systems to demonstrate ongoing particulate matter compliance. The ECS also discusses climate and carbon emission regulations and policy. Over the past decade, there has been significant activity in Congress on climate-related legislation to reduce GHG emissions and mandate renewable or carbon-free energy. Of note, several bills have been introduced that focus on an economy-wide carbon tax. These proposals typically impose an initial economy-wide price on carbon (e.g., dollars per ton CO_2), with varying degrees of escalation each year until the proposal's specific national emission reduction targets are achieved. The proposals contemplate initial pricing in a range from $15/ton to $52/ton and increase annually at varying rates. Another approach to pricing carbon, a clean electricity standard, has also been contemplated and additional legislative activity is expected in the future.

In this IRP, Georgia Power presents the potential risks the Company faces from the uncertainty around future federal regulatory and policy changes addressing carbon emissions not only of the utility industry but also of customer operations. This chapter further describes how Georgia Power plans to continue reducing the risk of potential carbon regulation or legislation in the context of unprecedented load growth and capacity resources needs.

9.2 – Environmental Compliance Cost Recovery

As with prior regulatory cycles, the Company anticipates the ECCR tariff will need to be updated in its next base rate case to appropriately reflect the incremental costs of environmental compliance. The incremental capital, O&M, and CCR ARO environmental compliance costs for which the Company seeks approval in this IRP are more specifically described in the Selected Supporting Information section of Technical Appendix Volume 2.

9.3 – Georgia Power's Climate Approach & Drivers

In addition to ensuring compliance with all applicable environmental rules, Georgia Power's planning process has historically considered a wide range of factors that inform long-term decision making, including customer needs, technology advancement, and developments and trends in climate policies. Georgia Power's well-balanced and diversified approach to a low-carbon future seeks to maximize optionality and operational flexibility to best serve customers. Under the state-regulated, vertically integrated utility model, Georgia Power relies on the IRP framework to specifically evaluate these potential future conditions and associated options with the Commission. This approach provides a holistic view into the reliability and resiliency needs of customers, with direct visibility into numerous elements of and planning for the electricity supply chain, such as generation, transmission, and distribution. To build on this approach and plan for the future, further consideration of a low-carbon future can utilize a net-zero approach, whereby any direct GHG emissions produced are counterbalanced by an equal amount of GHG removed through "negative carbon solutions," which may include various forms of CCS or carbon offset.

To benefit customers through competitive costs and reduced carbon emissions risk, Georgia Power's climate approach is consistent with the three pillars set forth in Southern Company's 2050 net-zero goal of pursuing a diverse energy resource portfolio, developing new technologies to lower GHG emissions, and constructively engaging with stakeholders.[37] Georgia Power recognizes that the feasibility of continued progress toward a low-carbon future, including a net-zero future, is highly dependent on the continued use of natural gas and continued technological advancements that will facilitate a reliable and economic low-carbon electricity supply.

As a direct result of working with the Commission, Georgia Power has demonstrated how progress towards decarbonization of electricity generation can be achieved through a state regulatory framework, resulting in more than 60% reduction in Scope 1[38] GHG emissions from direct Company operations since 2007. While planning for projected energy demand and considering new federal

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[37] In April 2018, Southern Company issued the *Planning for a low-carbon future* report. This report established goals to reduce carbon emissions. Southern Company, Planning for a low-carbon future (April 2018) https://www.southerncompany.com/content/dam/southern-company/pdf/corpresponsibility/Planning-for-a-low-carbon-future.pdf. In September 2020, Southern Company provided an addendum to that report with additional information on progress and plans to decarbonize the Southern Company System. This addendum, entitled Implementation and action toward net zero, included an update of the long-term goal to net zero emissions by 2050. Southern Company, Implementation and action toward net zero (September 2020), https://www.southerncompany.com/content/dam/southern-company/pdf/public/Net-zero-report.pdf.

[38] The World Resources Institute defines Scope 1 as "direct GHG emissions from sources that are owned or controlled by the company." World Resources Institute, Sustainability Dashboard Methodology, https://www.wri.org/sustainability-wri/dashboard/methodology.

GHG regulations, the Company is continuing to responsibly transition its coal generation fleet to more cost-effective natural gas and zero-carbon resources to continue to provide customers with clean, safe, reliable, and affordable electric service. During this period of extraordinary load growth, variation in total Scope 1 GHG emissions is expected due to a range of factors, including significantly increased electricity demand and fluctuations in fuel mix based on actual economic dispatch of resources. Continued prioritization of a flexible fleet transition that aligns with the timing and availability of technology advancements will be critical.

Georgia Power recognizes the importance of this climate approach being driven by optimizing costs and mitigating risks to customers. Focusing on keeping rates competitive remains critical to serving Georgia Power's customers. As such, Georgia Power's climate approach must allow for economic decisions that benefit all customers through the IRP process. As technology advances, the Company's proactive planning will help ensure customers realize the benefits of zero-carbon resources, negative carbon solutions, and enhanced energy efficiency initiatives as they become increasingly cost effective.

Finally, Georgia Power is proactively planning to mitigate future risks and challenges that could impact customer costs. Carbon risks include the uncertainty around federal regulatory and policy changes addressing the carbon footprint, not only of the utility industry, but also of customers, as detailed in Georgia Power's 2025 ECS document located in Technical Appendix Volume 1. In addition, potential challenges to future decarbonization for Georgia Power include the uncertainties around complex operational impacts of new technologies, limited geologic feasibility of CCS in Georgia, and potential infrastructure timeline restrictions associated with pipelines and grid transmission systems that could impact the transition of the generation mix to low-carbon resources. Taking proactive steps to incorporate evaluation of, and planning for, these risks and challenges is critical to help mitigate and shield customers from future costs.

9.4 – Georgia Power's Path and Progress

Georgia Power's outstanding track record for maintaining high reliability as the Company's generation fleet evolves is heavily rooted in Georgia's constructive state-regulatory framework, which has resulted in cost-effective, reliable, and low-carbon resource decisions. Georgia Power customers have benefitted from these decisions by having a diverse resource mix to mitigate risks and optimize costs as Georgia's economy continues to grow. Through the IRP process, the Commission has approved, and the Company has achieved or plans to achieve:

- Addition of over 3,000 MW of nuclear resources, including the completion of Plant Vogtle Units 3-4 to make Plant Vogtle the largest generator of clean energy in the United States
- Economic retirements of over 5,500 MW of coal, oil, and gas capacity
- Conversion of over 1,200 MW of coal resources to lower-carbon natural gas
- Addition of approximately 1,300 MW of advanced class natural gas combustion turbines
- Addition of more than 840 MW of BESS resources
- Addition of approximately 7,250 MW of solar and wind resources
- Addition of over 400 MW of biomass and landfill gas resources

- Reliable operation of approximately 1,100 MW of hydroelectric generation resources
- Implementation of over 4,450 GWh of energy efficiency (2011-2024)
- Completion of three renewable RFPs and three capacity RFPs

For over a decade, the Company's scenario planning process has included evaluations of higher and lower natural gas prices, along with variations in loads and carbon pricing, among other key factors. The 2022 IRP expanded these scenarios and sensitivities to address the potential for technology advancements, adjusted carbon pricing levels, electrification, and clean portfolio standards. For the 2025 IRP, Georgia Power maintained these expansions and added planning scenarios for the 111 GHG Rules, including the base case of 111-MG0, as discussed in Chapter 3.

Within the context of both the 111 GHG Rules and the increased capacity needs over the next decade and beyond, the Company's Unit Retirement Studies have identified the need to continue operations of coal units with comprehensive environmental controls at Plants Bowen and Scherer through 2035 or later. This recommendation is further addressed in Section 8.2 and is an example of how the Company is applying its long-term resource planning approach to responsibly transition its coal fleet on an appropriate timeframe to optimize costs and mitigate risks. The Company will continue to engage with Georgia EPD to address compliance for these coal units and any associated retirement targets to be included in Georgia's state plan for 111 GHG Rules compliance. State plan requirements will be incorporated within Georgia Power's long-term resource planning processes to establish a reliable and cost-effective transition to low-carbon resources in the future.

The 2025 IRP uses a well-balanced and diversified approach to meet future capacity needs through strategic expansion while continuing the Company's flexible economic fleet transition. The requests in this IRP will provide optionality and risk mitigation through a cost-effective, low-carbon, and reliable resource mix that will benefit all customers, while also providing clean energy options to meet the needs of customers with decarbonization goals. The proposed resource portfolio also positions the Company to address constraints and opportunities associated with current and potential future national climate policy.

9.5 – Potential Net-Zero Technology Evaluations

Sustained progress toward a lower carbon future requires technologies that are both technically feasible and economical. The Company is evaluating potential zero-carbon resources, such as advanced nuclear, long-duration energy storage, hydrogen, and wind energy, which may provide substantial value for customers as their costs decline and technology improves.

Negative carbon solutions are also an important component of a net-zero carbon approach and counterbalance direct GHG emissions from Company operations through either the capture and storage of GHGs or the application of carbon offset credits from qualifying GHG reduction projects. CCS could potentially be applied as an additional environmental control at a generating unit to remove GHG emissions at their source or could be used as direct air capture ("DAC") by removing GHGs from ambient air. While many of these negative carbon solutions are evolving or are in development, there are some unique challenges for CCS in Georgia. Unlike some neighboring states with extensive oil and gas exploration and development, Georgia has historically lacked the detailed geological capability and information needed for CCS deployment. Since 2021, however, Georgia Power has been partnering with Southern Company to evaluate the viability of CCS in Georgia. In

2024, test borings were completed at three sites, with a fourth site completed in January 2025, to gain information about underground geologic formations in northwest and southeast Georgia. While the ability to implement CCS is years away, these studies are necessary to keep diversified and potentially beneficial generation options viable for Georgia's future.

DAC technologies, which could provide flexibility in carbon capture, are being researched at the National Carbon Capture Center, which is managed and operated by Southern Company. Southern Company aims to explore flexible carbon removal solutions and support pilot projects with the DOE, universities, and DAC technology developers. Recently, these efforts resulted in a pilot project for testing on-site DAC in collaboration with Southern States Energy Board and Aircapture.[39]

9.6 – Customer Decarbonization Solutions

In addition to achieving significant emissions reductions from its own operations, Georgia Power has a proven track record for developing programs, including renewable energy, energy efficiency, and electrification programs, that support customer decarbonization goals. A growing number of customers are seeking clean energy solutions, with some focused on a carbon-free energy supply. When siting new facilities, many potential customers also consider a utility's ability to help them meet their sustainability goals. Chapter 10 provides details of the renewable customer programs proposed by the Company in this IRP.

In addressing carbon risk, Georgia Power will continue to consider how it can best serve customers by preparing for future challenges, leveraging existing resources, and growing flexibility in serving its customers. The 2025 IRP positions the Company to continue to provide its customers with clean, safe, reliable, and affordable electric service.

[39] AirCapture LLC, based in Berkeley, California, designs, develops, constructs, and operates on-site, modular CO_2 capture technologies, located at customer locations, which capture CO_2 from ambient air and point-source emissions and put the CO_2 directly into customers' production processes. The result is greener, cleaner, lower cost products that can help businesses reduce their carbon footprint. For more information, see https://www.aircapture.com.

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Chapter 10. Renewable & Resiliency Customer Programs

Georgia Power's portfolio of customer programs is continually evolving to offer innovative options that help customers meet their sustainability and resiliency goals. These programs help address customer needs and bolster economic growth within the state of Georgia. To meet the broad spectrum of customers' needs, Georgia Power seeks to continue to advance and innovate its program designs, including customer-sited generation programs and renewable energy subscription programs, while maintaining focus on enhanced System reliability and affordability for all customers.

Georgia Power proposes a suite of program options aimed at promoting customer satisfaction, sustainability, and economic growth in Georgia. Key initiatives and requests include:

- **Renewable Subscription Programs:**
    - CARES Distributed Generation: Expand the CARES program to offer customer subscriptions from smaller projects to C&I customers smaller than 3 MW, and to Residential customers through the Distributed Generation Community Solar subscription program.
    - CARES Utility Scale Subscription Program: Enhance subscription options from Utility Scale procurements, including longer participation windows and the option to procure from customer-identified renewable resources.
- **Customer-Sited Renewable Generation Programs:**
    - Customer-Sited Solar Plus Storage Pilot Program: Approval to launch a residential and small commercial solar and battery pilot program designed to add up to 50 MW of capacity through two participation options: Customer-Directed model (discrete events with performance-based payments) and Company-Directed model (continuous operation with upfront incentives).
    - Enhancements to the Customer Connected Solar Program, including:
        - Increase the facility size criteria to 250 kW minimum and 6 MW maximum.
        - Expand resource types to include BESS co-located with solar.
- **Distributed Energy Resource (DER) and Resiliency Programs:**
    - Continue the DER Customer Program portfolio with tariffs and programs that offer energy, capacity, and resiliency benefits, including a new customer-owned option for large customers.
- **Integration with DERMS:**
    - Develop and deploy a Distributed Energy Resource Management System to enhance the operational capabilities of DERs and optimize grid operations.

Georgia Power's portfolio of enhanced customer programs evolve continuously based on customer feedback and market demands and are designed to help meet customer needs and foster economic growth within Georgia. The following sections provide detailed information on the wide range of program offerings available.

10.1 – Renewable and Carbon Free Energy Subscription Programs

Georgia Power offers a broad portfolio of renewable subscription program options for customers interested in supporting the growth of renewable energy in Georgia and/or pursuing individual carbon reduction goals. Georgia Power continues to be committed to deploying renewable programs that meet customers' needs without compromising reliability and affordability. As customer needs for carbon-free energy continue to grow, the ability to offer a portfolio of programs that provide optimal value for all customers becomes more important for customer satisfaction and System reliability.

To maximize the value for both program participants and non-participants, it is critical that programs are designed in accordance with Commission-approved valuation methodologies and the Company's principles of program design. These principles include balancing the needs of individual customers while capturing benefits for all customers, minimizing cost shifting and upward rate pressure, and utilizing the RCB Framework to accurately and fairly value program resources. In addition to adhering to its principles of program design, the Company continues to place importance on incorporating customer feedback so that the program designs satisfy customer needs and encourage participation by interested customers. As a part of this commitment, Georgia Power continues to add cost-effective zero-carbon resources, supporting the sustainability goals of customers through programs like CARES.

Georgia Power has a long history of stakeholder engagement and has continued engagement with customers and stakeholders since the 2022 IRP and the 2023 IRP Update. This engagement has been focused on soliciting feedback on the Company's current program offerings to gain valuable insights on potential enhancements and new program options. As part of these formal and informal engagement sessions, the Company worked to educate customers on the program design principles and processes. Georgia Power is committed to offering options to meet a wide range of customer needs, and many concepts and suggestions identified through this robust engagement process are reflected in the Company's customer program portfolio as proposed in this IRP.

10.1.1 - Existing Renewable Programs

Georgia Power continues to implement renewable programs, as approved by the Commission, including renewable energy subscription programs, REC purchasing programs, and customer-sited generation programs. Customer interest in nearly all of the existing programs has been constant, and for many programs, has increased since the 2022 IRP, as customers are increasingly reliant upon renewable energy resources to help meet their carbon reduction and/or sustainability goals.

Renewable Subscription Programs

Georgia Power customers have the option to participate in renewable subscription programs that support the continued development of renewable resources here in Georgia and contribute towards a customer's carbon reduction goals while providing access to the benefits of grid connected renewable resources. Since the introduction of Georgia Power's first subscription-based renewable energy program in the 2016 IRP, the Commercial and Industrial Renewable Energy Development Initiative ("C&I REDI"), subscription programs have been an attractive program option to customers with sustainability goals. Building on the initial success of the C&I REDI program and its successor from the 2019 IRP, the CRSP program, Georgia Power was approved to procure an additional 2,100 MW in the 2022 IRP to support the CARES program.

The CARES program allows broader customer participation by allocating program capacity across multiple customer segments, including existing, MUSH and new load customers. Between both the CRSP and CARES Notice of Intent ("NOI") periods from 2020 to 2024, Georgia Power received more than 9,000 MW of customer interest to participate in these programs. To date, Georgia Power has been able to bring online 777.5 MW of renewable resources to supply the C&I REDI and CRSP subscription programs. Due to not selecting projects as part of the 2023/2024 Utility Scale RFP, the Company received approval by the Commission to roll forward unfilled MW to the future CARES 2023 Utility Scale RFP and offer CRSP subscribing customers the option to subscribe to existing resources from the REDI 1&2 resource portfolio. Additionally, CRSP NOI 2 customers were given the first option to subscribe to resources procured as part of the CARES 2023 Utility Scale RFP. As discussed in Chapter 8, Georgia Power is actively evaluating resources bid in through the CARES 2023 Utility Scale RFP to assess options and timelines that would enable the procurement of new renewable resources and meet the customer needs for the CRSP and CARES programs. Also, as discussed in Chapter 8 and further below, Georgia Power is proposing significant enhancements to the CARES resource procurements that would allow greater flexibility for customers, RFP participants, and the Company in the RFP and subscription processes.

Georgia Power's Community Solar program as modified in the 2022 IRP allows for residential customers on the standard residential rate or commercial customers on the General Service rate to subscribe to a portfolio of local solar facilities in one-kilowatt increments, known as a block. Customers pay a monthly subscription price and receive energy credit on their bill. As of December 31, 2024, there are currently 1,164 customers purchasing 2,037 blocks in the Community Solar program. In addition to the standard Community Solar program, Georgia Power also has the Income Qualified Community Solar program, in which a corporate sponsor can buy down up to 5,000 blocks from the existing portfolio of Community Solar facilities, which will then be available at 75% discounted subscription rate for income-qualified customers. This program offers the unique opportunity for corporate stakeholders to partner with Georgia Power in its commitment to offer equitable access to renewable energy and bill savings for income qualified customers. To date, no corporate sponsorships have been secured but Georgia Power remains committed to keeping this option available and continuing to develop Community Solar program options for customers. While Georgia Power is not requesting any modifications to this existing program, the Company is introducing the new Distributed Generation Community Solar Program detailed below as an additional subscription option for residential customers.

Renewable Energy Credit (REC) Programs

Georgia Power also works with customers to help satisfy their immediate renewable energy needs through REC purchasing options. The Company offers three REC purchase programs for customers interested in supporting the continued development of renewable resources while contributing towards their carbon reduction goals. The combination of these program options allows customers flexibility on quantity, timeline, and price of their REC purchases. Georgia Power is not requesting any modifications to these programs in this IRP.

- **Retail REC Retirement ("R3") Program** provides participating commercial and industrial customers the ability to claim renewable benefits from existing renewable resources through RECs from System resources that are already online or are in the process of coming online. The RECs and environmental attributes that would otherwise be retired on behalf of all customers are instead retired on behalf of the participating customer. To date, no customers are participating in this program; however, the Company expects that this option will continue to be a viable solution for customers as many pursue carbon goals with targets within the next 5 years.
- **Simple Solar** allows residential, commercial, or industrial customers to participate in the program by matching 50 or 100 percent of their monthly energy usage with solar RECs retired on their behalf. Customers can participate monthly with no long-term commitment. Since 2022, the program has consistently averaged approximately 1,800 customers subscribing to approximately 27,000 annually RECs. The Simple Solar Large Volume program sunset in December of 2022, following the approval of the Flex REC program in the 2022 IRP.
- **Flex REC** was approved in the 2022 IRP as a replacement for Simple Solar Large Volume, allowing for Georgia Power to procure greater quantities of RECs to meet growing customer demand and source the RECs from a broader variety of renewables including solar, wind and potentially other renewable resources. Since its inception, this program has maintained an average participation rate of 16 customers per month and now retires approximately 300,000 RECs annually on behalf of participating customers.

10.1.2 - CARES Utility-Scale Subscription Program Enhancements

Georgia Power's renewable energy subscription programs have been well received since their introduction, beginning with the C&I REDI program and continuing into the CRSP and the CARES programs. Interested customers subscribe to the output of renewable resources in a way that benefits both subscribers and non-subscribers alike, supporting the continued growth of renewable resources in Georgia. Demand for RECs through these subscription mechanisms has consistently outpaced the available supply—and that imbalance is exacerbated by a growing amount of new and existing customers with sustainability goals, as well as the procurement target shortfalls experienced in recent Utility Scale RFPs. Based on feedback from customers and developers, the Company proposes to modify both the RFP and subscription processes to provide as much flexibility as possible, increasing the chances of procuring beneficial renewable resources, and offering customers more options as they seek to secure benefits from renewable resources.

As detailed in Chapter 8, the Company proposes to modify the Utility Scale RFP process to include additional opportunities to procure renewable resources if customer subscription needs are not fully met through the traditional RFP process. Corresponding changes to the CARES subscription process will enable flexibility and optionality for customers to drive the procurement of additional resources beyond initial RFP targets, and modifications to the subscription pricing methodology will ensure that benefits are accurately allocated between participating and non-participating customers alike.

The first phase of the enhanced CARES program will mimic existing processes, and subscriptions will be offered through an enhanced NOI process and allocated to interested customers through a Commission-approved methodology. Once the Company has selected and entered into contracts with winning RFP participants, customers interested in participating in the CARES program will be offered subscriptions to the output of the resulting resource portfolio for terms of 10-30 years, in five-year increments. Subscriptions will be priced using either of the two CARES pricing mechanisms, the CARES REC-based fixed program portfolio charge with no hourly energy credit, or the CARES fixed program charge based on the PPA price, with a corresponding hourly energy credit. Georgia Power proposes to modify the price calculation methodology for the hourly energy credit to reduce the risk to non-participating customers by establishing reimbursement thresholds as part of the subscription.

If customer demand for subscriptions exceeds the amount of MW procured through the initial phase of the Utility Scale RFP, a buy-down process will commence to allow projects from the competitive tier to reprice their bid(s) at a price that offers a Total Net Benefit equal to or better than the average Total Net Benefit of the initial portfolio. Any additional MW procured will be made available to subscribers on the NOI list at the same subscription price.

If additional customer subscription needs remain after the initial NOI and RFP buy down processes are complete, or if customers indicate a desire to participate in a Customer Identified Resource procurement (also described in Chapter 8), the Company will implement the extended phase of the RFP. In the extended phase, the RFP will remain active and additional projects can be submitted into the RFP for consideration, as long as they offer a Total Net Benefits equal to or better than the average Total Net Benefit for the portfolio selected in the initial phase. This extended RFP process will offer interested customers additional opportunities to subscribe to available resources, either by submitting (i) a NOI to indicate interest in projects or a portfolio of projects independently submitted into the RFP, or (ii) a Customer Identified Resource into the RFP. Customers who submit a NOI in this extended phase must pay a participation fee and must provide appropriate collateral. Customers who submit a Customer Identified Resource will negotiate directly with a project developer to submit a bid that provides the same or better Total Net Benefits as the portfolio average from the initial phase of the RFP. Subscribers in the extended phase may choose either CARES pricing mechanism, the CARES REC-based fixed program portfolio charge with no hourly energy credit, or the CARES fixed program charge based on the PPA price, with a corresponding hourly energy credit. A modification to the price calculation methodology for the hourly energy credit will be introduced to reduce the risk to non-participating customers by establishing thresholds for reimbursement to subscribers. All RECs associated with a Customer Identified Resource bid will be retired on behalf of the subscriber.

10.1.3 - CARES Distributed Generation Subscription Program

To offer additional options to help customers meet their renewable and sustainability goals, the Company proposes to expand the CARES Program to include subscriptions from Georgia Power's DG renewable procurements. 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 and Residential customers.

Initial subscriptions will be available to eligible C&I customers from the initial procurement phase of each DG RFP. Interested customers will submit an NOI through a process similar to the current CARES Utility Scale process. Once the Company has selected and entered into contracts with winning RFP participants, interested customers will be offered subscriptions to the output of the resulting initial portfolio for term of at least ten years. Subscriptions will be priced using either CARES pricing mechanism, the CARES REC-based fixed program portfolio charge with no hourly energy credit, or the CARES fixed program charge based on the PPA price, with a corresponding hourly energy credit that includes a modification to the price calculation methodology to reduce the risk to non-participating customers. Georgia Power will retire the RECs on behalf of the subscribing customer.

If customer demand for subscriptions exceeds the amount of MW procured through the DG RFP, the Company will initiate the buy down process as detailed in Chapter 8, allowing unselected projects from the target list to enter into PPAs at a price that offers a Total Net Benefit equal to or better than the average for the portfolio selected in the initial phase. Additional MW will be made available in a pro-rata share to subscribers on the NOI list at the same subscription price.

If subscription needs for medium-sized customers are not fully met, or if a need for DG CARES subscriptions is identified from other customer groups or subscription programs (e.g. the Residential Distributed Generation Community Solar Program described below or large C&I customers over 3 MW with unmet subscription needs), the Company will implement the extended phase of the RFP. This phase allows for additional bids to be submitted into the RFP for consideration as long as they offer a Total Net Benefit equal to or better than the average for the portfolio selected in the initial phase. This extended RFP process will offer interested customers additional opportunities to subscribe to these resources, either by submitting (i) a NOI to indicate interest in projects or a portfolio of projects independently submitted into the RFP or (ii) a Customer Identified Resource. Customers who submit a NOI in this phase must pay a participation fee and must provide collateral as appropriate. Customers who submit a Customer Identified Resource will negotiate directly with a project developer to submit a bid that provides the same or better Total Net Benefits as the initial portfolio average. Subscribers in this phase may choose either the CARES REC-based fixed program portfolio charge with no hourly credit, or the CARES fixed program portfolio charge based on the PPA price with a corresponding hourly energy credit. All RECs associated with a Customer Identified Resource bid will be retired on behalf of the subscriber.

As part of the CARES Distributed Generation Subscription Program, the Company proposes to allocate up to 10 MW of the initial 50 MW target of each DG RFP to be offered for subscription by residential customers. The new Distributed Generation Community Solar Program will offer access to new DG facilities to residential customers using a similar but simplified CARES subscription methodology. These projects will be procured through the DG RFP process, and Residential customers will subscribe using a pricing mechanism based on the PPA price, with an energy credit calculated from the annual average value of the DG facility's production based on the Company's hourly operating costs of incremental generation per kWh. Georgia Power is also exploring opportunities to partner with 3rd parties to reduce subscription prices for lower income customers, enhancing the value proposition for eligible customers. If subscription needs are greater than the MWs available for subscription by Residential customers, additional resources may be procured through the extended RFP process outlined above, with the opportunity for developers to bring new subscribers and incremental projects. Details of the Distributed Generation Community Solar Program will be provided in a separate filing with the PSC pursuant to the approval of the program framework in this IRP.

These proposed modifications to the CARES Subscription Program are intended to offer customers more options to subscribe to carbon-free resources, while adding flexibility and optionality to the RFP process for bidders and subscribers alike. If approved, the details of the enhanced CARES Subscription Program will be submitted for Commission approval in a compliance filing after the conclusion of the 2025 IRP.

10.2 – Customer-Sited Generation Programs

Currently, customer generators can participate in one of four customer-sited renewable programs, which facilitate the installation of renewable resources on customer premises, typically solar or solar plus storage. These customer-sited programs are used primarily to offset customer energy consumption from the grid. Table 10.2 provides the current volume of customers and the aggregate AC capacity online by program and customer class. While the growth rate of residential customers installing solar BTM has decreased since the 2022 IRP, the growth rate of both commercial and industrial customers has increased. In general, customers in all classes are installing larger systems. Georgia Power continues to support customers through the design and interconnection process of BTM systems that are increasingly complex.

Table 10.2: Customer-Sited Renewable Generation Program Customer Volume

Online by Program	POI	Volume (# of customers) Capacity (AC-MW)		
		Commercial	Industrial	Residential
Energy Offset Only Customer systems designed to match usage and reduce grid consumption	BTM	194 16.21 MW	17 3.23 MW	887 6.37 MW
Renewable & Non-Renewable Resources Customer systems designed to reduce consumption and send excess back to the grid	BTM	480 22.73 MW	37 3.63MW	11,249 73.63 MW
Qualifying Facilities Customer or IPP systems designed to either: • Reduce consumption and send excess back to the grid • Receive compensation for generation to the grid	BTM or FTM	6 5.84 MW	2 1.14 MW	0 MW
Customer Connected Solar Systems designed to match usage and reduce grid consumption	FTM	1 1.5 MW	0 MW	0 MW
Total Customer Participation		**681** **46.28 MW**	**56** **8.0 MW**	**12,136** **80.0 MW**

Solar only resources installed through these programs help customers to meet some of their renewable and/or carbon reduction goals; however, the intermittency of these resources provides little support for customer resiliency requirements and minimal capacity benefit. Continued growth of these programs, particularly in the RNR program that compensates customer generators for energy pushed back to the grid at avoided cost plus the four cents per kilowatt hour adder creates a cost shift to non-participating customers. For compliance with the Georgia Cogeneration Distributed Generation Act of 2001 and the 2022 IRP and 2022 Rate Case orders, the Company will continue to offer these existing programs, but Georgia Power will offer new programs to encourage customers to install Solar Plus Storage customer-sited resources that offer more value to the grid.

Additionally, as the portfolio of customer-sited generation continues to grow, it will be increasingly important for Georgia Power to work with customers and solar stakeholders to ensure appropriate customer protections are in place, including transparency in program marketing related to costs, incentives and timelines, and quality workmanship to ensure system compliance with the Company DER Policy. Established consumer protection measures, like those supported by the Solar Energy Industries Association ("SEIA"), will be critical as new programs are introduced that may attract high customer participation and new installers, developers and original equipment manufacturers ("OEMs") who have less familiarity with Georgia Power's Rules and Regulations. Georgia Power is committed to working with the Commission, customers, and the solar industry to ensure appropriate consumer protections are in place as programs are implemented.

10.2.1 - Customer-Sited Renewable Generation

Georgia Power supports the development of customer-sited generation resources to help meet Georgia's growing energy needs. As discussed below, in this IRP the Company is proposing a new Customer-Sited Solar Plus Storage Pilot as well as enhancements to the Customer Connected Solar Program.

Since the 2022 IRP, there has been steady growth and adoption of residential, commercial, and industrial customer-sited solar generation. Georgia Power is committed to evaluating and modifying programs to create additional opportunities for a variety of customer-sited generation resources, including both Behind the Meter ("BTM") and in Front of the Meter ("FTM") options. If procured at economical prices, these resources can supply valuable renewable energy. Moreover, the addition of co-located BESS systems can provide capacity and flexibility to support customers' growing energy needs.

The Company currently has four programs that facilitate customer-sited solar generation, three of which allow Georgia Power to purchase the excess energy produced by customer-sited resources.

- **RNR**. The Renewable and Non-Renewable ("RNR") Tariff is available for residential customer generators with resources up to 10 kW, and commercial customer generators with resources up to 250 KW. The energy produced from these generators is primarily consumed onsite and offsets the purchase of electricity at retail rates for participating customers. These offsets create a loss in revenue greater than the resulting system cost savings, resulting in a shortfall in the recovery of fixed costs from RNR customers on energy-only rates, thereby shifting these costs to other customers. As ordered in the 2022 Rate Case, excess generation from RNR customers is purchased at the Company's solar avoided cost rate plus a four-cent per kilowatt-hour adder, which further increases costs for non-participating customers.
- **Energy Offset Only**. Customers who do not qualify for the RNR Tariff, or who choose not to participate, can enroll in the Energy Offset Program. Like with RNR, the energy produced by these customer generators is used to offset their purchase of electricity at retail rates. Again, this shifts costs to other customers if the customer generator is billed for retail electric service on an energy-only rate like the R rate. However, unlike with RNR, these customer generators are not compensated for any excess energy they export to the electric grid.
- **Qualifying Facilities**. Larger customer generators above the 250 kW RNR threshold may produce energy and be compensated as a Qualifying Facility ("QF"). In practice, these customers consume most of the energy they produce onsite. These customer generators are compensated for energy they export to the electric grid at the Company's hourly avoided cost rate.

- **Customer Connected Solar Program**. Customer solar generators under 3 MW can participate in the CCSP, which is a FTM program that compensates customers at a fixed price over a term of up to 20 years for all the renewable energy generated.

Georgia Power continues to evaluate the costs and benefits of procuring the energy produced by customer generators, including the impacts to System reliability and operations, interconnection costs and recovery of the costs to serve. Although solar resources provide valuable energy, the intermittency of these resources limits their capacity value. The largest procurement of energy from customer-sited resources comes from residential solar installations, which are compensated at prices above the value these resources deliver. To continue responsibly growing the portfolio of customer-sited solar generation the Company must compensate customer generators based on the actual value of their generation. The Company must also continue to monitor these resources and maintain optimal levels of operational control and reliability for the electric system. Notably, when coupled with dispatchable BESS, customer-sited renewable generation can provide additional capacity benefits to the electric system. Enhanced operational oversight and control of customer-sited generators with BESS will allow Georgia Power to better quantify the costs and benefits of these resources to the electric system.

As discussed in Section 10.3, the integration of DERMS will help maximize the benefits of customer-sited solar generation by enhancing the Company's operational oversight, and systems paired with BESS deliver the most value. Notably, only approximately 17% of customer-sited solar generation participating in a Georgia Power program include a BESS. Although customer adoption of solar plus storage is increasing, particularly in the residential market, the majority of customer generators remain solar-only resources. In this IRP, the Company proposes to offer a new portfolio of solar plus storage options for customer generators. These options are designed to encourage BESS-coupled systems, to minimize cost shifts associated to customer generation to non-participating customers, and to appropriately compensate customer generators for the value they deliver to the electric system.

Proposed Customer-Sited Solar + Storage Pilot Program

Pursuant to the 2023 IRP Update Order, the Company is proposing a Customer-Sited Solar Plus Storage Pilot Program for Residential and Small Commercial customers, which is designed to encourage additional customer-sited renewable generation resources pairing dispatchable BESS with BTM solar. These customer generators will be dispatched to meet System needs, thereby providing reliability and capacity benefits to all customers. The pilot will have two participation options: (1) a "Customer Directed" model in which the Company will identify discrete events and pay participating customers based on their performance during those events; and (2) a "Company Directed" option in which participating customers will make BESS available to the Company for continuous operation in exchange for a larger upfront incentive that is calculated based on the value their facility provides to the electric system. Participation will be open to residential customers with systems up to 20 kW and small commercial customers (peak load less than or equal to 250 kW) with systems up to 250 kW. Section 10.2.2 contains additional program details.

Through this pilot, the Company is initially seeking 50 MW of capacity, with 25 MW provided through the Customer Directed option and 25 MW through the Company Directed option. If the pilot capacity reaches these initial targets before the next IRP, Georgia Power will assess the pilot and may request an increase of the MW target from the Commission. As proposed, this pilot offers additional options to customer generators while helping meet the growing demand for electric energy. In addition, the pilot will provide the Company with valuable information regarding the technical capabilities, value, and market acceptance of customer-sited solar plus storage.

Customer-Connected Solar Program Strategy

Following the 2019 IRP, the Company was authorized to procure up to 25 MW of customer-sited solar generation through the CCSP. To date, there is only one participant in the program with a 1.5 MW facility. To realize the value of this program and offer customer generators an attractive FTM option to meet their renewable and sustainability goals, the Company proposes several enhancements designed to increase customer participation and provide more value to both the customer generator and all other customers.

These enhancements include the following:

- Increase the minimum and maximum facility size criteria to 250 kW and 6 MW, respectively
- Expand the resource type to include BESS paired with the solar
- Allow new customers to participate (as opposed to existing only)

The customer-sited solar plus storage program options introduced in the 2025 IRP will offer appropriate opportunities for a wide range of customers to add solar and storage resources to the System. These programs can add valuable renewable generation and dispatchable capacity resources that benefit the electric system, while compensating customer generators for the benefits provided and protecting non-participants from cost shifts. To this end, it is important that customer generators contribute to their share of retail electric service costs, with BTM customer generators receiving electric service on rates other than energy only rates like R and GS. Section 10.2.2 sets forth additional information regarding the proposed details of these new and enhanced customer-sited programs.

10.2.2 - Customer-Sited Renewable Programs

Residential and Commercial Solar Plus Storage Pilot Program

As introduced in Section 10.2.1, the Company is seeking approval for a Solar Plus Storage Pilot Program for residential and small commercial customers. Pairing storage with new or existing solar will provide valuable capacity resources to the System and additional resiliency for participating customers. As proposed, the Solar Plus Storage Pilot Program will target the addition of up to 50 MW of dispatchable storage resources, split evenly between the Customer-Directed and Company-Directed program options. Systems may be sized up to 20 kW for residential applications and 250 kW for commercial applications (no more than 125% of metered demand) and will be subject to appropriate application and interconnection requirements. Customer generators must take service on a Company-approved rate other than "R" (Residential) or "GS" (Commercial). The solar plus storage systems may be owned by the customer or another party, and customers can choose to participate in either the Customer-Directed or Company-Directed participation option.

- *Customer-Directed*

  The Customer-Directed option will be open for participation from both new and existing solar plus storage and standalone BESS resources.[40] In this participation option, Georgia Power will offer a small annual enrollment incentive in exchange for the ability to call upon the BESS during discrete utility events. The customer generator will be eligible for an additional payment on an annual schedule based on the performance of the BESS during event calls that calendar year. In the Customer-Directed option the BESS can be charged by the grid or the co-located solar resource. The minimum number of hours called in each annual period is 50, with a maximum event duration of four hours. If a customer opts out of an event and does not discharge their BESS, the customer will not receive any payment for that event. Outside of utility events, participating customers are able to use the BESS according to their needs and preferences, including resiliency. The Company intends to use a third-party aggregator to administer the program and facilitate participation from multiple brands and configurations of BESS assets.

  The upfront incentive payment is 15 $/kW of BESS capacity and is intended to encourage initial enrollment. An ongoing performance-based incentive of 1.50 $/kWh will be paid annually based on the energy discharged from the battery during Company called events. The total incentive value including the potential per event incentive is calculated based on the current system value of capacity. The capacity value reflected for the incentive payment is discounted to 75% to ensure value for non-participating customers. In recognition of the unique needs of low to moderate income customers and benefits provided by commercial businesses in municipalities, universities, schools, and hospitals ("MUSH") segments, an upfront incentive payment of 45 $/kW will be made available for eligible customers in those segments. The kW basis for the incentive payment will be based on the lower of (1) the maximum continuous discharge rate of the battery or (2) the energy storage capacity (kWh) divided by four.

- *Company-Directed*

  In the Company-Directed option, customers with new BESS assets that meet technical and performance requirements and are paired with new or existing BTM solar will be eligible to participate. As in the Customer-Directed option, the Company intends to use a third-party aggregator to administer the program, but requirements may restrict eligible technologies or configurations. Eligible customer generators will enter a ten-year contract to allow the BESS to be dispatched by Georgia Power. This contract will be tied to the premises and is intended to be conveyed to future customers in the same location in order to support the long-term nature of the agreement term. In return, the Company will provide an upfront incentive payment based on the current forecasted value of capacity to the System over the contract

[40] Customers that have installed storage only are eligible to participate in the Customer-Directed option.

term and is calculated consistent to other Company DER programs. The incentive value is 750 $/kW, which represents 75% of the associated system value of the storage capacity. Georgia Power will operate the BESS within manufacturer guidelines and will not discharge the battery below a 20% state of charge, preserving a minimum level of capacity to support customer resiliency. BESS in the Company-Directed model will be charged via the co-located solar and not from the electric grid.

In recognition of the unique needs of low to moderate income residential and MUSH commercial customers, an incentive of 1,000 $/kW will be offered for eligible customers in those segments. The kW basis for the incentive payment will be based on the lower of (1) the maximum continuous discharge rate of the battery or (2) 80% of the energy storage capacity (kWh) divided by two.

As proposed, the Solar Plus Storage Pilot Program is intended to support customer clean energy and resiliency goals while providing capacity resources to the System in an economic manner. The program design is structured to encourage additional market growth for flexible customer-sited generation, and allow for collaboration between the Company, Commission Staff, stakeholders, and customer generators with a goal of producing a program that offers benefits to all customers. As proposed, the Solar Plus Storage Pilot Program enables participation from a variety of customer types and sizes and creates opportunities to leverage additional funding sources to reduce the net costs to customers and the System. Participating customer generators will benefit from enhanced resiliency and optionality to participate according to their preferences, and non-participating customers will benefit from additional clean resources and dispatchable capacity added to the System. Georgia Power will continue to work with Staff and stakeholders to ensure a robust feedback process through the Pilot as the Company gains knowledge and experience related to maximizing the value these distributed resources can deliver to the System.

Customer Connected Solar Program Enhancements

The Company proposes to modify the existing CCSP guidelines to increase customer participation and include the addition of storage with these systems. By adding the option to include storage, the CCSP will provide a FTM option that offers similar renewable energy and resiliency benefits for the customer generator as a BTM system, while providing valuable energy and dispatchable capacity to the System. This program is designed to meet the unique needs of larger customers with an appropriate sharing of benefits between the customer generator and non-participants.

New and existing customers can participate in the enhanced CCSP with the addition of new solar and storage systems. The program will aim to fill the remaining 23+ MW originally approved for CCSP. RECs will be retired on behalf of participating customers from systems connected to the distribution system between 250 KW and 6 MW in size. Terms of 10, 15, 20, 25, 30, and 35 years will be offered, and customers or third parties can own the system. Compensation for participating customers will be based on the energy and capacity value the systems are projected to deliver.

These proposed changes to the CCSP, including the addition of BESS, allowance for larger projects, and availability for participation by new customers, are based on feedback received from stakeholders combined with the Company's desire to create a vibrant FTM option for customers with resiliency needs. The capacity value created by the dispatchable storage systems will benefit all

Georgia Power customers, support the reliability and affordability of the System, and support the growth of a sustainable customer-sited DG market in Georgia.

This portfolio of new and enhanced renewable energy programs, including options for subscriptions to grid connected utility scale and DG resources, as well as customer-sited renewable options, is designed to offer expanded options to interested customers to help them meet their carbon free goals, while also ensuring benefits to non-participating customers. These flexible options will increase the likelihood of securing resources at prices and terms that maximize System benefits through programs that fairly allocate the costs and benefits of renewable resources. These proposed program designs are the direct result of the experience Georgia Power has gained through offering customer focused renewable programs, direct feedback from stakeholders, and a commitment to accurate resource valuation and principles that ensure fairness for all customers.

10.3 – Distributed Energy Resources and Resilience

As both the electric system and customer needs evolve, customer interest in resiliency solutions continues to increase. Customer-sited resiliency assets have the potential to provide benefits to all customers if appropriate technologies are utilized and enrolled in programs that allow them to be dispatched for System needs. Recognizing this potential benefit, Georgia Power has increased its DER and Demand Response offerings. Georgia Power is continuing to work with customers to leverage investments that customers are making to benefit the electric system. This section of the IRP provides a summary of existing programs, requested modifications, and the introduction of a new large Customer Owned Resiliency program to provide additional optionality in the portfolio.

10.3.1 – DER Customer Program Pilot

Following the 2022 IRP, the Company worked with Commission Staff and intervenors to develop and finalize the Resiliency Asset Service (RAS-1) and Demand Response Credit (DRC-1) tariffs that underpin the DER Customer Program Pilot. These tariffs were approved in January 2023 and remain available for customers who are interested in this resiliency program solution. After working with interested customers and obtaining their feedback on the program, the Company developed and requested the Commission's approval of two additional supply-side DER programs in the 2023 IRP Update to offer more benefits to all customers and allow for a customer-owned option.

10.3.2 – DER Colocation Program

The DER Colocation program, as approved in the 2023 IRP Update Order and implemented through the DCL-1 tariff, is an optional tariff available to qualifying C&I customers. Through DCL-1, Georgia Power will own, operate, maintain, and control dispatchable DER at customer premises, and economically dispatch the resources to provide energy and capacity benefits to all customers. The DER will be connected to the electric system, thus allowing the Company to transmit the energy produced to the electric grid. During times of electric service outage, the DER will be used to provide participating customers with electric energy to support their operations. The DER generation will not impact the participating customer's billed retail electric service while participating in DCL-1. In exchange for the resiliency benefits provided by the DER, participating customers will make payments such that the resulting rate base value of the DER is below the system value realized over its asset life, thus benefiting all customers. DER technology that may be utilized under DCL-1 includes, but is not limited to, natural gas generators, diesel generators, and other technologies with firm fuel supply. Customers participating under the DCL-1 tariff will also be required to enter into a program agreement with Georgia Power to further establish the terms and conditions of participation.

10.3.3 – DER Customer-Owned Program

The DER Customer Owned Program, as implemented through the DCO-1 tariff, is an optional program available to qualifying commercial and industrial customers and operates much like the DER Colocation program, but with a few key differences. Through DCO-1, Georgia Power will operate and control customer-owned, new dispatchable DER located at customer premises and economically dispatch the resources to provide energy and capacity benefits to all customers. Like with DCL-1, interconnection of the DER with the Company's electric system will allow the energy produced by the DER to be transmitted to the electric grid. During times of electric service outage, the DER will provide participating customers with electric energy to support their operations. The DER generation will not impact the participating customer's billed retail electric service while participating in DCO-1. Under this program, Georgia Power will provide participating customers with a credit on their electric bills in exchange for the Company's use of the customer's DER for economic dispatch. The DCO-1 credit will be based on the capacity and energy value of the participating customer's DER over the period during which they subscribe to the DCO-1 program. As a condition of participation, customers will be required to enter a program agreement with Georgia Power that will further establish the terms and conditions of participation. To reflect the Company's ongoing capacity needs and provide additional value to both participating and non-participating customers, Georgia Power is requesting a program modification to DCO-1 to allow for contract terms up to 15 years, based on mutual agreement by the Company and participating customer.

10.3.4 – Large Customer Owned Resiliency Program

The Company is proposing a new resiliency program for large C&I customers. This program offering will allow customers to maintain ownership of their DER while providing the Company with operational certainty that demand response will materialize when called upon. The benefit to participating customers of the Large Customer Owned Resiliency program is the ability to receive economic value for firm load reductions on the System, while also accelerating the timeframe in which capacity can be recognized. Like all the Company's DER programs, non-participating customers benefit through the shared savings model where capacity is being procured at a discount relative to generic capacity costs. By continuing to expand its DER offerings, the Company is seeking to provide flexible options to meet the needs of a diverse set of customers across the state with varying preferences and requirements.

10.3.5 – Demand Response and Dynamic Pricing Tariffs

The Company continues to offer its customers the following menu of additional demand response programs and dynamic pricing tariffs:

- Real Time Pricing, which offers customers marginal pricing for incremental load; as prices increase, customers can respond by reducing their demand.

- Demand Plus Energy Credit ("DPEC"), which is an interruptible service tariff that provides commercial and industrial customers with a demand credit for the potential of demand reduction, plus an energy credit when DPEC is called on.

- Curtailable Load, an interruptible tariff similar to DPEC that provides customers with a demand credit for event-based demand reductions over a longer-term contract.
- Demand tariffs, which align with the Company's cost of service and encourage peak demand management.

- Time of Use tariffs, which provide customers with pricing signals during different periods of the day that reflect the varying cost of energy across seasons and time periods (peak and off-peak) and encourage customers to modify their usage accordingly.

10.3.6 – Electric Transportation Technology Advancements and Pilots

As the energy landscape continues to evolve, new and emerging technologies have the potential to fundamentally alter the way energy is created, transported, and ultimately consumed. As a core component of the planning process, the Company monitors technology advancements to ensure it is prepared and ready to adopt new technologies that benefit customers and the grid. The Company has identified two areas related to the EV market for further study: managed charging and vehicle-to-everything ("V2X").

Managed Charging

Charging technology has advanced such that EVs can be charged using pre-determined or dynamic scheduling that can benefit both the driver and the utility. Managed charging is categorized as either passive or active. Passive managed charging attempts to influence customer behavior by simply incenting customers to charge during off peak times through rate structures. Active managed charging allows utilities to directly control the charging schedule and shift charging to off peak hours as needed. The Company is currently administering a residential pilot with both passive and active managed charging participation options for customers. The Company seeks to understand driver behavior and charging patterns, implement and gauge customer response to managed charging, and study how managed charging techniques can be used to mitigate the potential impacts of future EV adoption on the System.

In addition, Southern Company is currently partnering with Ford Pro on a fleet managed charging pilot. The six-month pilot with Ford Pro involves more than 200 F-150 Lighting trucks across Southern Company's fleet of company vehicles. Utilizing established charging depots and over 150 chargers equipped with Ford Pro charging software, the pilot will explore both dynamic pricing optimization and demand response. The goal of the pilot is to understand how EV managed charging programs can be maximized to benefit both fleet operations and grid efficiency, to inform customers transitioning to EV fleets, and to provide guidance for future Company EV program design.

Vehicle-to-Everything ("V2X")

The Company is studying V2X technology and its potential impacts to customers and to the System. EV deployment means a significant number of underutilized batteries will be in the market and that energy could be of benefit. V2X enables vehicles to transfer energy stored in batteries to buildings, houses, and the grid. By leveraging V2X, the Company could enhance System flexibility, resiliency, and economics. By understanding the different layers of V2X and their level of complexity, it can create a smarter, more connected energy ecosystem while delivering more sustainable transportation solutions. The Company plans to evaluate the V2X technology through a pilot, starting with public school systems, to install up to 10 chargers.

10.4 – Integration with DERMS

Georgia Power's strategy to meet customer needs through programs while leveraging the value of those programs to the electric grid includes the ability to integrate with a DERMS. The Company's DERMS acts as an enabling hardware and software system that allows customer programs focused on demand side reduction and other customer participation models to be leveraged more fully as reasonable and allowed based on the technology and customer preference. Enhanced operational capabilities through DERMS can allow for dispatch and optimization of DER assets that will benefit future grid planning and operations if the Company is allowed to control DER devices in addition to having visibility and forecasting capabilities as approved in the 2022 Rate Case Order.

Georgia Power has invested in a DERMS to meet the requirements specified in the 2022 Rate Case Order. Georgia Power selected a DERMS vendor following an RFP and is currently executing a plan that was developed jointly with subject matter experts throughout the Company and the DERMS vendor. This execution includes integration with existing and upcoming operating systems such as Advanced Distribution Management System ("ADMS") and Energy Management System ("EMS") to allow for DER visibility and forecasting through DERMS. To utilize DER for grid optimization via DERMS, the Company is also developing power plant controller ("PPC") and DER gateway requirements that will be necessary to facilitate these enhanced operational capabilities. The Company expects the execution of this project scope to be complete by the end of 2025.

To ensure reliable operation of the grid and more fully realize the value of the growing number of DERs in Georgia, DERMS must have enhanced control the DER devices in addition to the existing operational capabilities of visibility and forecasting. Having enhanced control of DERs will allow for these devices to be dispatched to ensure optimal grid operation across different resource types and within program parameters. The enhanced operational capability to control DERs can expand potential use cases and value to the grid, including the ability to recognize capacity value for aggregated assets. This grid value can be reflected in program incentive valuations.

While an initial DERMS investment was approved in the 2022 Rate Case Order, the Company continues to pursue alternate funding opportunities for DERMS investments. As such, Georgia Power has included funding for DERMS in its application for funding through the DOE's Title 17 loan opportunities that support Energy Infrastructure Reinvestment. The Company assumes these projects will qualify for the DOE Title 17 Loan Program that affords additional financial savings.[41] The development of this application and eligibility of DERMS to be included is ongoing with the DOE.

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[41] See footnote 32.

10.5 – Additional Customer Need Driven Options

In addition to the new programs and program enhancements described above, the Company is exploring solutions such as technologies to ensure grid reliability with changing generation dynamics, carbon-free capacity resources like advanced nuclear and long-duration energy storage, and other innovative solutions to accommodate more renewable and carbon-free resources. Additionally, Georgia Power is actively engaging with stakeholders to identify the most impactful decarbonization strategies and is committed to transparency in its efforts to foster a collaborative approach. The Company will continue to evaluate and refine these opportunities, presenting specific proposals to the Commission for approval as appropriate, ensuring that all initiatives deliver both System reliability and economic benefits for all customers. These opportunities may require Commission-approved programs to facilitate participation by large load customers willing to fund these decarbonization enabling technologies. The Company will submit to the Commission for approval these customized solutions that facilitate large customer sustainability goals.

Chapter 11. Transmission

Georgia Power's Ten-Year Plan, included in this IRP, is based upon current planning assumptions and identifies the transmission improvements needed to maintain a strong and reliable transmission system. As a compliment to its Ten-Year Plan, Georgia Power has included a comprehensive bulk transmission plan of the Georgia ITS summarizing studies, project lists, processes, data files, and other information required by the amended Rules adopted by the Commission in Docket No. 25981.

11.1 – Transmission Planning Principles

The transmission planning principles provide an overview of the standards and criteria used for transmission expansion and upgrade proposals. These principles are designed to help ensure the coordinated development of a reliable, economical, and efficient electric system and the long-term benefit of transmission users. These principles emphasize proactive planning to ensure timely System adjustments, upgrades, and expansions. Georgia Power's transmission planning principles are:

1. Identify and recommend projects that are consistent with the Guidelines for Planning the ITS and the Guidelines for Planning the Southern Company Electric Transmission System.
2. Identify and recommend projects that are consistent with the NERC Reliability Standards.
3. Minimize costs associated with the transmission system expansion, considering the impact on System reliability and operations.
4. Identify projects with sufficient lead-time to provide for the timely construction of new transmission facilities.
5. Coordinate transmission system plans with the plans developed by Georgia Power's Planning & Policy group.
6. Coordinate transmission system plans with all ITS Participants and other transmission owners to enhance reliability and minimize associated costs.
7. Coordinate future transmission plans with other Georgia Power departments, other ITS Participants, other SCS departments and the regions surrounding the Southeast in the project development and planning processes.
8. Maintain adequate interconnections with neighboring utilities.
9. Ensure proper awareness throughout the integrated planning process of the importance of adequate transmission improvements and System expansion.
10. Utilize existing resources (e.g., reusing rights of way, increasing the capacity of existing facilities, implementing voltage conversions, and constructing double-circuit lines) and favoring substation projects and innovative solutions over new line construction where feasible.
11. Minimize transmission losses when cost effective.
12. Avoid the loss of life to transmission equipment from forced operation at higher loading levels.

These principles provide guidance to transmission planners and/or planning authorities that are called upon to explore existing issues and any future problems encountered in the transmission planning process.

11.2 – Ten-Year Transmission Plan

Georgia Power is a participant in the ITS, which consists of the physical equipment necessary to transmit power from the generating plants and interconnection points to the local area distribution load centers. Electric transmission facilities in the ITS are individually owned and maintained by ITS Participants. Transmission Planning identifies investments required to maintain sufficient capacity in the ITS to reliably meet the electricity needs of the public. These decisions are based on technical and economic evaluations of options that can meet these needs. ITS Participants are responsible for meeting their full load requirements, including generation, as well as for making necessary improvements to their transmission facilities and building new facilities to accommodate load growth, changes in network flows, System reliability, or System operations.

The Company develops a transmission planning model of the transmission system for each year of the next ten years. The Company used this planning model to identify transmission constraints and to evaluate alternative solutions that address those constraints. The planning model also serves as the basis for the 2024 Georgia ITS Ten-Year Plan, which incorporates updates to generation and load growth for all ITS Participants, including changes since the 2022 IRP and 2023 IRP Update.

All Transmission Planning information required by the Commission in Docket Nos. 25981 and 31081 is provided in Technical Appendix Volume 3.

11.3 – Strategic Transmission

A key component of an IRP is the ability to consider impacts to the transmission system when making generating resource decisions. The Company routinely takes these considerations into account by completing evaluations separate from the standard ten-year transmission planning processes. Since the 2022 IRP, Georgia Power, in conjunction with the ITS Participants, developed and initiated the projects in Table 11.3 below to improve power transfer from South Georgia to North Georgia (formerly known as the North Georgia Reliability & Resiliency Action Plan), prepare the transmission system for generation fleet transitions, and maintain System reliability.

Table 11.3: Strategic Transmission Projects

Project Number	Project Name	Need Date	GA ITS Ten Year Plan	Project Status
18774	GTC: Heard County - Tenaska 500kV (Second Line)	12/1/2025	2021 2022 2023 2024	Construction
19334	GTC: Lagrange Primary - North Opelika 230kV Line	6/1/2026	2021 2022 2023 2024	Engineering
09662	GTC: East Walton 500/230kV Area Project	6/1/2027	2022 2023 2024	Engineering
16887	Butler - Thomaston 230kV Line Conversion	6/1/2029	2024	Planning
19950	GTC: Dresden - Talbot 500kV Line	6/1/2029	2022 2023 2024	Engineering
21062	Ashley Park - Wansley 500kV Line	6/1/2029	2024	Planning
21123	GTC: Tenaska - Wansley 500kV Line	6/1/2029	2024	Planning
20857	Cavender Drive - Tributary 230kV Line	6/1/2030	2024	Planning
21013	GTC: Cavender Drive 500/230kV Area Project	6/1/2030	2024	Planning
21014	GTC: Cavender Drive - Buzzard Roost 230kV Line	6/1/2030	2024	Planning
21063	Farley (APC) - Tazewell 500kV Line	6/1/2030	2024	Planning
21073	GTC: Big Smarr - Tomochichi 500kV Line	6/1/2030	2024	Planning
21076	GTC: Talbot #2 - Tazewell 500kV Line	6/1/2030	2024	Planning
21077	GTC: Rockville - Tiger Creek - Warthen 500kV Line	6/1/2030	2024	Planning
21093	North Spa 230kV Area Project	6/1/2030	2024	Planning
21094	GTC: Tiger Creek - Rockville - North Spa 230kV Line	6/1/2030	2024	Planning
21113	GTC: Hartwell Energy - Middle Fork 230kV Line	6/1/2030	2024	Planning
21116	Goshen Area 230kV Area Project	6/1/2030	2024	Planning
21118	MEAG: Athena - Union Point - Warrenton 230kV Line Conversion	6/1/2030	2024	Planning
20756	Hatch - Wadley 500kV Line	6/1/2031	2024	Planning
21099	MEAG: Pio Nono 230/115kV Area Project	6/1/2031	2024	Planning
09661	McGrau Ford - Middle Fork 500kV Line	6/1/2033	2024	Planning
21075	GTC: East Walton - Middle Fork 500kV Line	6/1/2033	2024	Planning

In addition to these existing strategic planning efforts, the Company will implement additional planning considerations and process enhancements to address long-lead integrated system projects, beyond traditional ten-year transmission planning and more generic generation expansion, to ensure that evolving System needs can be met with the most economical long-term options. This will require longer term locational modeling trends to support System needs across a range of likely futures with significant growth in the demand for electricity, renewable growth, aging resources, and new resource needs guided by the IRP process.

Across the utility industry, it is becoming more common to extend the transmission planning horizon, with FERC Order No. 1920 driving the industry towards longer planning horizons in regional planning processes. While these FERC requirements and some industry activity may push the boundaries on what future assumptions are reasonable for planning, strategic planning beyond ten years will be an important part of the Company's planning process going forward. The Company's longer-term planning horizon will ensure projects are identified with sufficient lead time to provide timely construction and optionality while balancing the appropriate local customer value with regional considerations. System needs and growth continue to move at an extraordinary pace, and it is prudent to strategically plan and expand transmission capacity with local future siting considerations that accommodate a range of generation options and load growth needs and keep Georgia Power customer needs at the forefront. Demonstrating a robust, locally developed plan to meet these longer-term needs will also feed into future regional planning processes, focusing on projects that provide value and benefit customers.

11.4 – Innovative Solutions

As part of Georgia Power's commitment to implementing a diverse portfolio of solutions to meet customers' needs, the Company continues to deploy innovative transmission solutions using GETs, where these technologies are safe, reliable, and economical. GETs refers to a portfolio of technologies focused on increasing grid capacity and enabling the reliable integration of inverter-based generation resources such as solar and BESS. The Company also deploys other innovative solutions, including non-wires alternative ("NWA") solutions. There is some overlap between GETs and NWA solutions, with the difference being that GETs can be deployed in a variety of circumstances, including wires-based solutions.

The Company has a vast GETs portfolio. Consistent with EPRI, the Company defines GETs across four main categories: advanced conductors, advanced power flow control, topology optimization, and adaptive line ratings. Advanced conductors provide a wires-based solution, while the remaining categories include enhancements to technology, data, or software related to existing transmission facilities. The Company also includes flexible AC transmission systems ("FACTS"), which can include both new transmission facilities and enhancements to existing transmission facilities. GETs-based solutions are driven by different grid needs, and projects including GETs are initiated from three main organizations in the transmission business unit: planning, real-time operations, and maintenance.

Georgia Power has a track record of deploying economical, innovative solutions, including GETs, to meet the needs of its customers and the electric grid. For example, the Company has used advanced conductors for over a decade and continues to work with industry leaders such as EPRI to test new advanced conductor products as they are proven safe and reliable. Many of these projects are driven by the need to reconductor or upgrade a transmission line. Additionally, in 2024, Georgia Power deployed its first transmission-connected static synchronous compensator ("STATCOM") and has plans for additional STATCOM devices on the grid, which support grid reliability through voltage support. Volume 3 of Section A of this filing contains more information about the Company's transmission planning process, including the evaluation of potential transmission solutions such as GETs. Finally, the Company continues to evaluate the potential benefits of dynamic line rating ("DLR") capabilities, which can provide additional data to inform the real-time operating capacity of transmission lines beyond the Company's long-standing use of ambient-adjusted rating ("AAR") capabilities. The Company's real-time operations organization drives the integration and evaluation of this technology. These examples demonstrate the range of technologies within the GETs portfolio and how they are integrated into Georgia Power's transmission operations based on their respective values.

11.5 – Federal and State Funding Opportunities

The Company continues to seek alternate sources of funding where applicable to minimize cost impacts to customers, including transmission system investments. For example, Georgia Power has been selected to negotiate approximately $160 million in DOE grant funding through the 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. Negotiations are ongoing with the DOE to establish the terms and conditions of this award. Additionally, Georgia Power is pursuing DOE Title 17 loan opportunities that support Energy Infrastructure Reinvestment. Some of this application includes transmission investments from the Company's portion of the Georgia ITS Ten-Year Transmission Plan, strategic transmission projects, and continued deployment of innovative solutions including GETs. The Company assumes these projects will qualify for the DOE Title 17 Loan Program that affords additional financial savings.[42] The development of this application and eligibility of transmission projects to be included is ongoing with the DOE.

Georgia Power is also pursuing funding opportunities administered by state entities and, as such, has applied for funding through the Grid Resilience grant program administered by the Georgia Environmental Finance Authority ("GEFA"). The Company is currently awaiting the outcome of this application. If selected for funding by GEFA, the application 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 to customers.

[42] See footnote 32.

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Conclusion & Action Plan

The 2025 IRP proposes a reliable, economical, and diverse resource mix that will ensure Georgia Power can continue to meet its customers' evolving energy needs with a diverse mix of energy resources, a comprehensive environmental compliance strategy, enhanced reliability and resilience, and state-of-the art technology. As in past IRPs, the 2025 IRP utilizes a scenario-based approach that focuses on seasonal planning, strategic expansion of the generation fleet that includes extensions and upgrades at existing generating facilities, continued investment in hydro-powered resources, regular and flexible RFPs, and strategic expansion of the transmission system, while integrating innovative solutions to manage transmission constraints. Georgia Power's proposals to extend operations of existing System resources is a commitment to exploring all options to economically and reliably serve growing customer demand without diminishing the Company's long-term commitment to an economic transition of generation fleet.

Georgia Power proposes to expand and modify several of its renewable and DER customer programs through the addition of storage resources in front of the meter, behind the meter, and on site at customer locations, and refocus its successful portfolio of demand-side programs to better target the needs of low to moderate income customers.

Georgia Power's 2025 IRP appropriately balances many diverse interests in offering a comprehensive strategy to supply growing customer load reliably and economically, while acknowledging the need to continue to provide customers clean, safe, reliable, and affordable service at the quality they deserve and expect. In addition to the items specifically contained in the conclusion of the Executive Summary, pending Commission approval where necessary, the Company plans to take the following actions:

- Build, operate, and maintain the necessary generation and power delivery infrastructure to ensure adequate reliability and serve the needs of Georgia.
- Continue to work with the ITS Participants to advance the strategic portfolio of projects to address the long-term transmission planning and operational needs of the state.
- Execute the ECS, as approved by the Commission, to comply with government-imposed environmental requirements.
- Continue to provide and assess opportunities to integrate cost-effective resources.
- Implement and integrate a DERMS system and related technologies that will provide enhanced System monitoring, assessment, and operational capabilities, and control of resources.
- Utilize the methodologies outlined in the RCB Framework for resource evaluations.
- Issue an All-Source Capacity RFP in the third quarter of 2025 to meet its capacity needs for 2032 and 2033.

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Attachment A – Application for Certification of Capacity from Plant Scherer Unit 3

<u>Executive Summary</u>

Capacity Resources

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 markets, (2) in a manner that would not adversely affect the Company's ability to continue to sell such resources into the wholesale markets, and (3) in a manner such that the RFP process was not adversely affected.

Georgia Power's offer of approximately 187 MW of wholesale capacity is consistent with the mandates of the Commission-approved Wholesale Action Plan. Additional information on the Company's offer can be found in Technical Appendix Volume 1. The Company now files for certification pursuant to Commission Rule 515-3-4-.04(3)(f) and O.C.G.A. § 46-3A-3 and requests that acceptance and certification, or rejection, of this offer be determined in the final decision issued in this case.

History of the Capacity Resource Offer

On December 20, 2007, the Commission initiated a proceeding to consider whether it has the authority to require Georgia Power to first make capacity available to retail customers through a competitive solicitation before entering into any new contracts with wholesale customers. The Company and various intervenors submitted comments on the matter. Based upon the comments received, the Commission amended its Procedural and Scheduling Order in Docket No. 26550-U to provide the Parties an opportunity to make a good faith effort to resolve the matter and develop a resource specific plan of action. The Company conferred with other Parties and developed a plan that would provide for the Company to offer certain wholesale capacity blocks to the retail jurisdiction on a one-time basis. At its Administrative Session on July 15, 2008, the Commission approved this Plan, and, subsequently, the Commission Order approving the Plan was filed on July 30, 2008. The Commission has previously certified several offers to bring resources to the retail jurisdiction under the Plan, including resources at Plant Scherer Unit 3 and resources from Wholesale Blocks 1, 2-4, and 5&6.

The Company's offer in this 2025 IRP to bring additional capacity from Plant Scherer Unit 3 to the retail jurisdiction is occurring though the Commission noted completion of the Wholesale Action Plan after offers extended as part of the 2022 IRP. Georgia Power is offering approximately 187 MW of capacity from Plant Scherer Unit 3 to the retail jurisdiction to serve retail customers when the capacity becomes available from each existing wholesale contract. Please see the Technical Appendix Volume 1 for the Company's offer of this capacity.

Certification Process

Terms of Purchase

In a similar manner as the Wholesale Action Plan, the Company offers wholesale block capacity at current market prices based on MDA analysis. Because the ultimate outcome of the 111 GHG Rules is subject to legal uncertainty due to ongoing petitions for review, the Company is providing MDA values for both 111-MG0 and MG0 planning scenarios. The Company requests approval for whichever scenario is appropriate based on the status of the 111 GHG Rules at the time the wholesale capacity would be placed in retail service. The specific terms of the offer of the wholesale block capacity to the retail jurisdiction are found in Technical Appendix Volume 1.

Cost of Purchase

The Company proposes to offer the wholesale block capacity under the same MDA construct utilized in previous offers. The MDAs for the Plant Scherer Unit 3 blocks would serve to impact base rates by adjusting projected retail revenues. The offer included in Technical Appendix Volume 1 details the purchase cost for the wholesale block capacity.

Proposed Ratemaking Treatment

The assets shall be placed in retail rate base at their current book value, accompanied by the utilization of 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.

Similar to other assets in retail rate base, all prudently incurred actual fuel costs associated with the resources will be recovered through the Fuel Cost Recovery process. The assets shall be placed in retail rate base and treated in the same manner as all other generation assets in retail rate base. There are no additional warranties for performance, and the recovery of all costs will be consistent with the recovery for cost on all other retail rate base generation assets. For example, costs incurred due to a change in law will be included in retail rate base; the Company does not warrant any level of availability or heat rate; actual non-fuel O&M costs shall be recovered in retail base rates. For additional details on the offer, please see Technical Appendix Volume 1.

Depreciation Analysis

The estimated depreciation schedule for the Plant Scherer Unit 3 can be found in Technical Appendix Volume 1.

Cost Benefit Analysis

To offer wholesale block capacity on terms equivalent to that which the Company could obtain in the then-current market, Georgia Power is utilizing the same MDA construct as previous offers. By utilizing an MDA for each wholesale block resource, the book value of each resource is accompanied by the MDA such that retail customers pay for the market value of each wholesale block resource. In this 2025 IRP, the Commission can weigh the cost of adding existing, reliable resources to the retail jurisdiction. Please refer to the Company's offer presented in the Technical Appendix Volume 1 for the economics Plant Scherer Unit 3 offer.

Analysis of Transmission Impacts

There are no transmission facilities added, modified, or avoided as a result of this certification request.

Impact on 2025 IRP

The wholesale block capacity's impact to retail customers is not reflected in the various analyses presented in the 2025 IRP. The addition of approximately 187 MW of capacity would defer future capacity needs in accordance with the date placed in retail service for each wholesale block.

Commission Rule Exception to the RFP Requirement

Pursuant to the Commission's Order Approving Georgia Power Company's Proposal to Offer Certain Wholesale Capacity Blocks to the Retail Jurisdiction, the Company had been required to offer certain wholesale capacity blocks to retail customers. As part of the Commission's Order, the Company agreed to offer the wholesale blocks as they become available 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. As noted earlier, the Company has made several offers to the Commission since the Commission Order approving the Company's Proposal was issued on July 30, 2008. The Order recognizes the importance of timing of the offers to the ability to remarket capacity and the importance of the IRP in that process. Through prior Orders certifying wholesale-to-retail capacity, the Commission has exempted that capacity from the Commission's RFP requirements under Commission Rule 515-3-4-.04. Pursuant to Commission Rule 515-3-4-.04(3)(f)(3), which exempts from the RFP requirement "supply-side capacity resources of extraordinary advantage that require immediate action," and 515-3-4-.04(3)(f)(6), the Company requests that the wholesale block capacity offer of approximately 187 MW of capacity be exempted as provided by Commission Rule.

<u>Conclusion</u>

As set forth in the preceding sections, the wholesale block capacity is offered to the retail jurisdiction in a similar manner as previous offers and provides a reliable source of capacity and energy from existing resources for Georgia Power customers at a cost-effective market price. Therefore, the Company requests that the Commission accept and certify this offer.

Attachment B – Application to Amend the Certificate of Capacity for Plant McIntosh Units 10-11 and 1A-8A

Executive Summary

Capacity Resources

As discussed in Section 8.3 of the 2025 IRP Main Document, Georgia Power plans have identified opportunities to increase capacity at Plant McIntosh Units 10-11 and Units 1A-8A. Plant McIntosh Units 10-11 currently operate with winter planning capacities of 692 and 685 MW, respectively, while Plant McIntosh Units 1A-8A have winter planning capacities of approximately 95 MW each.

The identified upgrades provide economic opportunities to meet growing energy needs while leveraging existing resources. The proposed upgrades for Plant McIntosh Units 10-11 and 1A-8A provide cost-effective solutions to meet capacity needs, offering a balance of peaking capacity and efficient NGCC capacity.

- **Plant McIntosh Units 10-11**: Projected to achieve an incremental capacity of 194 MW (winter). This enhancement increases the capacity of these combined cycle units while also improving the heat rates in some operating modes. This upgrade will also give these NGCCs the ability to operate power augmentation (admission of steam to the combustion turbine to increase mass throughput and power output) and peak firing in winter conditions, as well as the ability to operate peak fire and power augmentation simultaneously.
- **Plant McIntosh Units 1A-8A**: Will provide an additional 74.4 MW (winter) of incremental capacity. These upgrades are designed to provide additional economic peaking capacity, ensuring the plant can meet peak demand periods more effectively. In addition to increasing capacity, these replacement components are of lower cost than the in-kind replacement parts, leading to a reduction in the capital budget moving forward. This reduction can be explained by changing market conditions and reduction in the available in-kind replacement parts.

To facilitate the identified upgrades to Plant McIntosh Units 10-11 and Units 1A-8A, the Company is seeking a Certificate Amendment as required by O.C.G.A. § 46-3A-3(b) and Commission Rule 515-3-4-.08.[43] Additional information is provided in the Unit Upgrade Analyses in Technical Appendix Volume 1.

Progress of Construction or Implementation

The projects associated with these upgrades will begin after approval of this certification amendment. The Plant McIntosh Units 10-11 upgrades are expected to be completed with an assumed in-service date of January 1, 2029. The Plant McIntosh Units 1A-8A upgrades are expected

[43] The CT upgrades at Plant McIntosh Units 1A-8A Georgia Power are projected to increase summer capacity by more than 15%, necessitating Certificate Amendment. Although the winter capacity increase is not projected to increase capacity by more than 15%, Georgia Power is seeking a Certificate Amendment for all projects associated with these upgrades out of an abundance of caution.

to be completed with staggered in-service dates starting in 2026 and continuing to phase in through 2032.

Cost Benefit Analysis

Upgrades to Plant McIntosh Units 10-11 and Units 1A-8A will provide many needed benefits for customers as articulated in the foregoing sections. The economics of the project are shown in detailed cost-benefit analysis in Technical Appendix Volume 1. This analysis clearly demonstrates that these upgrades are in the best interests of customers. For information on the costs and benefits associated with the capacity upgrades at Plant McIntosh, see the Unit Upgrade Analyses section of Technical Appendix Volume 1.

Proposed Ratemaking Treatment

The capacity updates at Plant McIntosh Units 10-11 and Units 1A-8A will be recovered through traditional (rate base and revenue requirement) ratemaking.

Analysis of Transmission Impacts

Transmission considerations for new resources or capacity additions at existing generation sites, as is the case with the McIntosh upgrades, require evaluation of transmission-related costs. The two primary categories of transmission-related costs are costs associated with delivery of the generation and the cost associated with interconnection of the generator to the transmission system. After evaluation, the NGCC upgrades will require the advancement of two prior-planned transmission projects. The incremental cost of advancement has been included in the analysis. The stability portion of the transmission evaluation has not been completed at time of filing for the NGCC or CT upgrade opportunities. In the event stability analysis identifies any additional costs, The analysis will be updated as appropriate. There are no incremental transmission costs for the CT upgrade opportunity, either for delivery or interconnection.

Impact on 2025 IRP

The capacity upgrades at Plant McIntosh Units 10- 11 and Units 1A-8A are not reflected in the various analyses presented in the 2025 IRP. The addition of approximately 269 MW of capacity would defer future capacity needs by the capacity upgrade amounts for these units.

<u>Conclusion</u>

As set forth herein, the requested upgrades to McIntosh Units 10-11 and Units 1A-8A will assist in Georgia Power's provision of economical and reliable supply of electric power and energy for retail customers. The request contained in this 2025 Certification Amendment Application is in the public interest and substantially complies with the relevant Commission rules. Therefore, the Company requests that the Commission approve this Certificate Amendment.

Attachment C – Planned and Committed Resources

Attachment C lists the Company's planned and committed resources included in the 2025 IRP. The Company's capacity needs are listed in Chapter 8. When determining capacity needs, the Company considers the summer and winter capacity contribution, including the appropriate capacity equivalence adjustments. For detailed seasonal values and capacity equivalence information, please see Technical Appendix Volume 1.

C.1 – Company-Owned Resources – Conventional

Fuel Type	Resource Name	2025 Summer Retail Capacity (MW)[A]	2025 Winter Retail Capacity (MW)[A]	Georgia Power Ownership	In-Service Date	Assumed Unavailability[B]
Nuclear	HATCH 1	438.9	451.4	50.10%	12/1975	08/2054
Nuclear	HATCH 2	442.4	454.4	50.10%	09/1979	06/2058
Nuclear	VOGTLE 1	538.6	559.7	46.83%[44]	05/1987	01/2067
Nuclear	VOGTLE 2	539.5	563.0	46.83%	05/1989	02/2069
Nuclear	VOGTLE 3	510.5	510.5	45.70%	07/2023	07/2083
Nuclear	VOGTLE 4	510.5	510.5	45.70%	04/2024	04/2084
Coal	BOWEN 1	714	740	100.00%	10/1971	12/2035
Coal	BOWEN 2	705	760	100.00%	09/1972	12/2035
Coal	BOWEN 3	910	950	100.00%	12/1974	12/2035
Coal	BOWEN 4	910	910	100.00%	11/1975	12/2035
Coal	SCHERER 1	75.2	75.2	8.40%	03/1982	12/2035
Coal	SCHERER 2	72.2	72.2	8.40%	02/1984	12/2035
Coal	SCHERER 3	537.4	537.4	75.00%	01/1987	12/2035
Gas	MCDONOUGH 4	855	934	100.00%	01/2012	12/2057
Gas	MCDONOUGH 5	850	928	100.00%	04/2012	12/2057
Gas	MCDONOUGH 6	840	930	100.00%	10/2012	12/2057
Gas	MCINTOSH 10	670.1	691.7	100.00%	06/2005	12/2050
Gas	MCINTOSH 11	670.1	685	100.00%	06/2005	12/2050
Gas	GASTON 1 GAS	127	127	50.00%	05/1960	12/2034
Gas	GASTON 2 GAS	128	128	50.00%	07/1960	12/2034
Gas	GASTON 3 GAS	102	102	50.00%	06/1961	12/2034
Gas	GASTON 4 GAS	102.6	102.6	50.00%	06/1962	12/2034
Gas	YATES 6 GAS	322.7	322.7	100.00%	07/1974	12/2038
Gas	YATES 7 GAS	325.7	325.7	100.00%	04/1974	12/2038
Oil	GASTON A	7.7	9.7	50.00%	06/1970	12/2034
Gas	MCDONOUGH 3A	-	31.4	100.00%	05/1971	None
Gas	MCDONOUGH 3B	-	31.4	100.00%	05/1971	None

[44] Georgia Power owns 45.7% of Plant Vogtle Units 1-2 but purchases approximately 1.13% of capacity and energy through a long-term buyback from MEAG.

Gas	MCINTOSH 1	82.2	94.5	100.00%	05/1995	None
Gas	MCINTOSH 2	82.2	94.5	100.00%	04/1995	None
Gas	MCINTOSH 3	82.2	94.5	100.00%	06/1994	None
Gas	MCINTOSH 4	82.2	94.5	100.00%	05/1994	None
Gas	MCINTOSH 5	82.2	94.5	100.00%	05/1994	None
Gas	MCINTOSH 6	82.2	94.5	100.00%	05/1994	None
Gas	MCINTOSH 7	82.2	94.5	100.00%	04/1994	None
Gas	MCINTOSH 8	82.2	94.5	100.00%	02/1994	None
Oil	MCMANUS 3A	44.4	55.4	100.00%	01/1972	None
Oil	MCMANUS 3B	44.4	55.4	100.00%	01/1972	None
Oil	MCMANUS 3C	44.4	55.4	100.00%	01/1972	None
Oil	MCMANUS 4A	44.4	55.4	100.00%	12/1972	None
Oil	MCMANUS 4B	44.4	55.4	100.00%	12/1972	None
Oil	MCMANUS 4C	44.4	55.4	100.00%	12/1972	None
Oil	MCMANUS 4D	44.4	55.4	100.00%	12/1972	None
Oil	MCMANUS 4E	44.4	55.4	100.00%	12/1972	None
Oil	MCMANUS 4F	44.4	55.4	100.00%	12/1972	None
Oil	MCMANUS DIESEL	-	-	100.00%	01/1964	None
Gas	WARNER ROBINS 1	80	93	100.00%	05/1995	None
Gas	WARNER ROBINS 2	80	93	100.00%	05/1995	None
Oil	WILSON 1A	54.5	65.5	100.00%	12/1972	None
Oil	WILSON 1B	54	65.0	100.00%	12/1972	None
Oil	WILSON 1C	38.2	53.2	100.00%	12/1972	None
Oil	WILSON 1D	24.5	39.5	100.00%	02/1973	None
Oil	WILSON 1E	52.1	59.1	100.00%	04/1973	None
Oil	WILSON 1F	43.1	59.1	100.00%	04/1973	None
Oil	WILSON DIESEL	-	-	100.00%	01/1972	None
Oil/Gas	YATES 8	441	356.6	100.00%	12/2026	12/2071
Oil/Gas	YATES 9	441	356.6	100.00%	05/2027	05/2072
Oil/Gas	YATES 10	441	356.6	100.00%	08/2027	08/2072

C.2 – Company-Owned Resources – Hydroelectric

Fuel Type	Resource Name	2025 Summer Retail Capacity (MW)[A]	2025 Winter Retail Capacity (MW)[A]	Georgia Power Ownership	In-Service Date	Assumed Unavailability[B]
Hydro	ROCKY MTN 1-3 PS	190.1	190.1	25.4%	1995	None
Hydro	WALLACE DAM 1-2, 5-6 PS	213.1	213.2	100%	1980	None
Hydro	BARTLETTS FERRY 1-4	71.1	72.5	100%	1926-1951	None
Hydro	BARTLETTS FERRY 5-6	118.2	120.6	100%	1985	None
Hydro	BURTON 1-2	9.5	8.7	100%	1927	None
Hydro	FLINT RIVER 1-3	6.4	5.7	100%	1921-1925	None
Hydro	GOAT ROCK 3-8	28.7	29.3	100%	1912-1956	None
Hydro	LLOYD SHOALS 1-6	22.5	22.5	100%	1911-1917	None
Hydro	MORGAN FALLS 1-7	7.7	8.4	100%	1904	None
Hydro	NACOOCHEE 1-2	6.0	6.0	100%	1926	None
Hydro	NORTH HIGHLANDS 1-4	34.4	34.8	100%	1963	None
Hydro	OLIVER 1-4	53.2	52.4	100%	1959	None
Hydro	SINCLAIR 1-2	43.8	43.9	100%	1953	None
Hydro	TALLULAH 1-6	72.9	72.9	100%	1913-1920	None
Hydro	TERRORA 1-2	17.4	17.5	100%	1925	None
Hydro	TUGALO 1-4	52.3	52.4	100%	1923	None
Hydro	WALLACE DAM 3-4	114.8	114.9	100%	1980	None
Hydro	YONAH	28.7	28.6	100%	1925	None

C.3 – Company-Owned Resources – Renewables and Storage

Fuel Type	Resource Name	2025 Nameplate Capacity (MW)[C]	Georgia Power Ownership	In-Service Date	Assumed Unavailability [B]
Solar	COMER COMMUNITY SOLAR	2.2	100%	1/5/2018	12/31/2053
Solar	FALCONS	1.0	100%	10/16/2017	12/31/2052
Solar	FORT BENNING	30.0	100%	12/31/2015	12/31/2050
Solar	FORT GORDON	30.0	100%	10/4/2016	12/31/2051
Solar	FORT STEWART	30.0	100%	10/4/2016	12/31/2051
Solar	FORT VALLEY STATE UNIVERSITY	10.8	100%	1/21/2022	12/31/2057
Solar	GUYTON COMMUNITY SOLAR	3.6	100%	7/25/2019	12/31/2054
Solar	KINGS BAY	30.2	100%	12/1/2016	12/31/2051
Solar	MCINTOSH CLOSED ASH POND	10.0	100%	7/9/2024	7/8/2059
Solar	MCLB	31.2	100%	2/16/2018	12/31/2053
Solar	MOODY AFB	49.5	100%	6/23/2020	12/31/2055
Solar	LAGRANGE (RIGHT OF WAY) SOLAR	0.8	100%	2/28/2020	12/31/2055
Solar	ROBINS AFB	128.0	100%	4/15/2021	12/31/2056
Solar	UGA SOLAR	1.0	100%	2/1/2016	12/31/2051
Solar	UNASSIGNED SELF-BUILD SOLAR	-	100%	1/2030	12/2065
Solar	WAYNESBORO COMMUNITY SOLAR	2.4	100%	6/28/2019	12/31/2054
BESS	2019 BESS DEMO	2	100%	4/2027	4/2037
4-hr BESS	2019 IRP BESS DEMO – FORT STEWART 4 HR BESS	13	100%	4/2027	4/2047
2-hr BESS	2022 IRP MCGRAU FORD 2 HR BATTERY	265	100%	11/2026	11/2046
4-hr BESS	2023 IRP UPDATE – HAMMOND	57.5	100%	11/2026	12/2046
4-hr BESS	2023 IRP UPDATE – MCGRAU FORD PHASE 2	265	100%	11/2026	12/2046
4-hr BESS	2023 IRP UPDATE – MOODY AFB	49.5	100%	11/2026	12/2046
4-hr BESS	2023 IRP UPDATE – ROBINS AFB	128	100%	11/2026	12/2046
4-hr BESS	MOSSY BRANCH	65.0	100%	10/4/2024	9/30/2044

C.4 – Power Purchase Agreements – Conventional

Fuel Type	Resource Name	2022 Summer Retail Capacity (MW)[A]	2022 Winter Retail Capacity (MW)[A]	PPA Start Date	PPA Term Length	PPA End Date
Gas	ADDISON 1 (WEST GA)	153.5	185.9	1/1/2015	15	5/31/2030
Gas	ADDISON 3 (WEST GA)	148.5	180.9	1/1/2015	15	5/31/2030
Gas	DAHLBERG 1, 3, 5	224.1	261.6	1/1/2028	10	12/31/2037
Gas	DAHLBERG 2	74.1	88.4	6/1/2010	15	5/31/2025
Gas	DAHLBERG 2 & 6	149.2	175.1	6/1/2025	10	5/31/2035
Gas	DAHLBERG 4	73.9	87.1	1/1/2015	15	5/31/2030
Gas	DAHLBERG 6	75.1	87.7	6/1/2010	15	5/31/2025
Gas	DAHLBERG 8	74.2	86.2	6/1/2010	15	5/31/2025
Gas	DAHLBERG 8-10	224.5	262.3	6/1/2025	10	5/31/2035
Gas	DAHLBERG 10	75.2	89	6/1/2010	15	5/31/2025
Gas	EXELON HEARD 1	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 2	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 3	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 4	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 5	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 6	157.5	157.5	6/1/2010	20	5/31/2030
Gas	HARRIS 1	640.6	667.7	6/1/2016	14	5/31/2030
Gas	HARRIS 2	660.4	689.5	12/1/2024	10	11/30/2034
Gas	MID-GEORGIA COGEN	300.0	300	6/1/1998	30	5/31/2028
Gas	MONROE 1 & 2	309	360	12/1/2024	15	11/30/2039
Gas	WANSLEY 7	597.9	621.7	12/1/2024	10	11/30/2034

C.5 – Power Purchase Agreements – Renewables and Storage

Fuel Type	Resource Name	Nominal Capability (MW)[C]	PPA Start Date	PPA Term Length	PPA End Date	# of Projects
Biomass	2022 IRP BIOMASS - AGE	70	11/30/2029	30	11/29/2059	1
Biomass	ALBANY RENEWABLE ENERGY	49.5	6/1/2017	20	5/31/2037	1
Biomass	GEORGIA RENEWABLE POWER FRANKLIN LLC	58	12/14/2019	27	5/31/2047	1
Biomass	GEORGIA RENEWABLE POWER MADISON	58	12/14/2019	27	5/31/2047	1
Biomass	GREEN POWER SOLUTIONS	29	6/1/2015	20	5/31/2035	1
Biomass	INTERNATIONAL PAPER - FLINT RIVER	26.9	6/1/2015	22	10/7/2036	1
Biomass	INTERNATIONAL PAPER - PORT WENTWORTH[45]	29.5	4/13/2017	20	5/31/2037	1
Biomass	PIEDMONT GREEN POWER	55	4/19/2013	20	9/30/2032	1
LFG	COCA-COLA	6.3	12/1/2015	20	11/30/2035	1
LFG	CONYERS RENEWABLE ENERGY	3.1	4/25/2018	19	5/31/2037	1
LFG	MAS GEORGIA LFG - OAK GROVE	6.2	8/2/2016	20	5/31/2036	1
LFG	MAS GEORGIA LFG - PINE RIDGE	6.3	6/1/2016	20	5/31/2036	1
LFG	MAS GEORGIA LFG - RICHLAND CREEK	10.5	12/1/2016	20	11/30/2036	1
LFG	WM RENEWABLE ENERGY LLC	6	6/1/2010	27	5/31/2037	1
Wind	BLUE CANYON	250	1/1/2016	20	12/31/2035	2
Solar	ASI CLASSIC 210 MW - DG S1320	0.8	5/1/2013	20	4/30/2033	10
Solar	ASI CLASSIC 210 MW - DG S1420	9.3	5/1/2014	20	4/30/2034	25
Solar	ASI CLASSIC 210 MW - DG S1520	28.6	5/1/2015	20	4/30/2035	108
Solar	ASI CLASSIC 210 MW - DG S1620	2.4	5/1/2016	20	4/30/2036	5
Solar	ASI CLASSIC 210 MW - DG W1420	17.0	1/1/2014	20	12/31/2033	50
Solar	ASI CLASSIC 210 MW - DG W1520	18.5	1/1/2015	20	12/31/2034	70
Solar	ASI CLASSIC 210 MW - DG W1620	1.4	1/1/2016	20	12/31/2035	7
Solar	ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER	4.1	4/23/2015	20	4/22/2035	1
Solar	ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	20.0	12/14/2015	20	12/13/2035	1

[45] Please note that both International Paper – Flint River and International Paper – Port Wentworth now include incremental energy additions from the 2024 Biomass RFP.

Solar	ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	16.0	12/16/2016	20	12/15/2036	1
Solar	ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	20.0	2/12/2016	20	2/11/2036	1
Solar	ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR	18.9	1/1/2016	20	12/31/2035	1
Solar	ASI CLASSIC 210 MW - US 2: HECATE ENERGY	20.0	11/14/2016	20	11/13/2036	1
Solar	ASI CLASSIC 210 MW - US 2: SOLAR GLYNN	17.7	12/1/2016	20	11/30/2036	1
Solar	ASI PRIME 525 MW - DG S1625	0.1	5/1/2016	25	4/30/2041	3
Solar	ASI PRIME 525 MW - DG S1635	0.3	5/1/2016	35	4/30/2051	6
Solar	ASI PRIME 525 MW - DG S1725	4.0	5/1/2017	25	4/30/2042	5
Solar	ASI PRIME 525 MW - DG S1730	6.1	5/1/2017	30	4/30/2047	6
Solar	ASI PRIME 525 MW - DG S1735	7.0	5/1/2017	35	4/30/2052	16
Solar	ASI PRIME 525 MW - DG S1815	0.2	5/1/2018	15	4/30/2033	3
Solar	ASI PRIME 525 MW - DG S1820	0.0	5/1/2018	20	4/30/2038	2
Solar	ASI PRIME 525 MW – DG S1825	0.3	5/1/2018	25	4/30/2043	
Solar	ASI PRIME 525 MW - DG S1835	0.1	5/1/2018	25	4/30/2043	3
Solar	ASI PRIME 525 MW - DG W1725	13.6	1/1/2017	25	12/31/2041	32
Solar	ASI PRIME 525 MW - DG W1730	6.1	1/1/2017	30	12/31/2046	16
Solar	ASI PRIME 525 MW - DG W1735	1.9	1/1/2017	35	12/31/2051	10
Solar	ASI PRIME 525 MW - DG W1815	0.5	1/1/2018	15	12/31/2032	15
Solar	ASI PRIME 525 MW - DG W1820	0.3	1/1/2018	20	12/31/2037	10
Solar	ASI PRIME 525 MW - DG W1825	9.2	1/1/2018	25	12/31/2042	13
Solar	ASI PRIME 525 MW - DG W1830	22.4	1/1/2018	30	12/31/2047	21
Solar	ASI PRIME 525 MW - DG W1835	6.3	1/1/2018	35	12/31/2052	27
Solar	ASI PRIME 525 MW - US 1: BUTLER SOLAR	100.0	12/13/2016	30	12/12/2046	1
Solar	ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR	79.9	1/1/2016	25	12/31/2040	1
Solar	ASI PRIME 525 MW - US 1: PAWPAW SOLAR	30.0	3/11/2016	30	3/10/2046	1
Solar	ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	51.0	1/1/2017	30	12/31/2046	1
Solar	ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	76.5	1/1/2017	30	12/31/2046	1
Solar	ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	101.3	1/1/2017	30	12/31/2046	1
Solar	AXIUM US SOLAR HOLDINGS (SD&D)	1.0	6/1/2012	15	5/31/2027	1

Solar	LSS 50 MW - HSH PEMBROOKE	1.0	6/3/2015	20	6/2/2035	1
Solar	LSS 50 MW - SIMON SOLAR FARM	30.0	6/1/2015	20	5/31/2035	1
Solar	LSS 50 MW - SOLAR D&D CAMILLA	16.0	6/1/2015	20	5/31/2035	1
Solar	LSS 50 MW - SOLAR D&D CAMP (MERIWETHER COUNTY)	3.0	6/1/2015	20	5/31/2035	1
Solar	REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	120.0	12/11/2019	30	12/10/2049	1
Solar	REDI 1400 MW - C&I: TANGLEWOOD SOLAR	57.5	3/12/2020	30	3/11/2050	1
Solar	REDI 1400 MW - DG CS S1920	0.5	5/1/2019	20	4/30/2039	2
Solar	REDI 1400 MW - DG CS S1925	2.7	5/1/2019	25	4/30/2044	3
Solar	REDI 1400 MW - DG CS S1930	5.9	5/1/2019	30	4/30/2049	4
Solar	REDI 1400 MW - DG CS S1935	14.0	5/1/2019	35	4/30/2054	10
Solar	REDI 1400 MW - DG CS W1925	1.6	1/1/2019	25	12/31/2043	2
Solar	REDI 1400 MW - DG CS W1930	0.6	1/1/2019	30	12/31/2048	1
Solar	REDI 1400 MW - DG CS W1935	10.6	1/1/2019	35	12/31/2053	11
Solar	REDI 1400 MW - DG S2030	2.0	5/1/2020	30	4/30/2050	1
Solar	REDI 1400 MW - DG S2035	75.3	5/1/2020	35	4/30/2055	33
Solar	REDI 1400 MW - DG W2030	2.5	1/1/2020	30	12/31/2049	1
Solar	REDI 1400 MW - DG W2035	6.9	1/1/2020	35	12/31/2054	3
Solar	REDI 1400 MW - US 1: QUITMAN SOLAR	150.0	12/16/2019	30	12/15/2049	1
Solar	REDI 1400 MW - US 1: SOUTHERN OAK SOLAR ENERGY	160.0	2/4/2020	30	2/3/2050	1
Solar	REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	200.0	9/5/2020	30	9/4/2050	1
Solar	REDI 1400 MW - US 2: QUITMAN II	150.0	11/30/2021	30	11/29/2051	1
Solar	2022/2023 US - TIMBERLAND SOLAR	140.0	10/18/2024	30	11/29/2054	1
Solar + Storage	2022/2023 US - FLINT RIVER SOLAR	200.0	11/30/2024	30	11/29/2054	1
Solar + Storage	2022/2023 US - WADLEY SOLAR	260.0	11/30/2024	30	11/29/2054	1
Solar + Storage	2022/2023 US - WASHINGTON COUNTY SOLAR	150.0	11/30/2024	30	11/29/2054	1
Solar + Storage	REDI 1400 MW - US 2: HICKORY PARK	195.5	11/30/2021	30	11/29/2051	1
Solar + Storage	REDI 1400 MW - US 2: COOL SPRINGS	213.0	11/30/2021	30	11/29/2051	1
Solar	2019 IRP CCSP DG	25.0	3/7/2022	30	11/29/2054	1
Solar	2019 IRP REDI CS2	3.0	3/1/2022	30	2/29/2052	1

Solar	2019 IRP RENEWABLES - US 2	750.0	11/30/2024	30	11/29/2054	1
Solar	2019 IRP RENEWABLES – DG S2230	4.8	5/1/2022	30	4/30/2052	1
Solar	2019 IRP RENEWABLES – DG S2330	36.0	5/1/2023	30	4/30/2053	1
Solar	2019 IRP RENEWABLES – DG S2430	0.6	3/8/2024	30	3/8/2054	1
Solar	2019 IRP RENEWABLES – DG W2330	24.3	1/1/2023	30	12/31/2052	1
Solar	2019 IRP RENEWABLES – DG W2430	23.2	9/30/2023	30	9/29/2053	1

Notes:

A) The retail capacity values listed reflect the capacity value attributable to retail adjusted for Georgia Power ownership and capacity equivalence. The capacity listed reflects the capacity in 2025 unless otherwise noted. For resources not online in 2025, the capacity listed is consistent with the expected capacity at the resource's in-service date. Please refer to Technical Appendix Volume 2 Resource Mix Study supporting documentation for annual capacity values.

B) IRP modeled unavailability dates are based on the resource's assumed useful life, but no earlier than January 1, 2030 unless otherwise noted. Useful life assumptions are 60-year life for steam units, 45-year life for CT/CC units, and the length of the current operating license for nuclear units. Blackstart, restoration, and hydro resources do not assume an unavailability date.

C) The nominal capability listed reflects the capacity in 2025 unless otherwise noted. For resources not online in 2025, the nominal capacity listed is consistent with the capacity at the resource's in-service date. These values do not reflect capacity equivalence. Please refer to Technical Appendix Volume 2 Resource Mix Study supporting documentation for seasonal capacity values.

C.6 – Demand-Side Options

Resource Name	Type	2025 Summer Retail Capacity (MW)[D]	2025 Winter Retail Capacity (MW)[D]
Real Time Pricing Extreme Day Ahead	Price Responsive Demand	5.1	2.7
Real Time Pricing Extreme Hour Ahead	Price Responsive Demand	134.9	124.2
Conservative Voltage Reduction Level 1	Power Delivery	231.2	200.3
Conservative Voltage Reduction Level 2	Power Delivery	231.2	200.3
Demand Plus Energy Credit	Interruptible Load	92.1	92.1
Thermostat Energy Management Program	Interruptible Load	34.1	29.0

Notes:

D) For Demand-Side Options, the ratings are based on the program capacity adjusted for the ELLC and losses. The ELCC is a measure of the effect of a demand-side option on generating System reliability.

Attachment D – Retirements Since 2007

Unit	MW	Primary Fuel	IRP or Authority	Retirement Date
McDonough 1	254	Coal	Docket 24506-U	2/29/2012
McDonough 2	254	Coal	Docket 24506-U	9/30/2011
Branch 1	250	Coal	2011 IRP Update[46]	4/16/2015
Branch 2	319	Coal	2011 IRP Update	10/1/2013
Mitchell 4C	33	Oil	2011 IRP Update	3/26/2012
Branch 3	509	Coal	2013 IRP	4/16/2015
Branch 4	507	Coal	2013 IRP	4/16/2015
Kraft 1-3	201	Coal	2013 IRP	10/13/2015
Kraft 4	115	Gas/Oil	2013 IRP	10/13/2015
McManus 1	43	Oil	2013 IRP	4/16/2015
McManus 2	79	Oil	2013 IRP	4/16/2015
Yates 1-5	579	Coal	2013 IRP	4/16/2015
Boulevard 2	14	Oil	2013 IRP	7/17/2013
Boulevard 3	14	Oil	2013 IRP	7/17/2013
Bowen 6	32	Oil	2013 IRP	4/25/2013
Mitchell 3	155	Coal	2016 IRP	8/2/2016
Mitchell 4A	31	Oil	2016 IRP	8/2/2016
Mitchell 4B	31	Oil	2016 IRP	8/2/2016
Kraft 1 CT	17	Gas/Oil	2016 IRP	8/2/2016
Intercession City	143	Oil	2016 IRP[47]	8/2/2016
Hammond 1	110	Coal	2019 IRP	7/29/2019
Hammond 2	110	Coal	2019 IRP	7/29/2019
Hammond 3	110	Coal	2019 IRP	7/29/2019
Hammond 4	510	Coal	2019 IRP	7/29/2019
McIntosh 1	142.5	Coal	2019 IRP	7/29/2019
Estatoah 1	0.1	Hydro	2019 IRP	7/29/2019
Langdale 5-6	0.2	Hydro	2019 IRP	7/29/2019
Riverview 1-2	0.1	Hydro	2019 IRP	7/29/2019
Wansley 1	466.5	Coal	2022 IRP	8/1/2022
Wansley 2	466.5	Coal	2022 IRP	8/1/2022
Wansley 5A	32.1	Oil	2022 IRP	8/1/2022
Boulevard 1	18.6	Oil	2022 IRP	8/1/2022
Total	**5,547**			

[46] The 2013 IRP final order revised the retirement date of Plant Branch Unit 1 to be consistent with the retirement date of Plant Branch Units 3 and 4.
[47] In the case of the Intercession City CT unit, located in Florida and previously co-owned with Duke Energy Florida, the Company exercised its contractual option in May 2015 to terminate the transmission service and sell the Company's previous ownership interest in the unit to Duke Energy Florida.

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Attachment E – Major Models Used in the IRP

E.1 – Load Forecasting

E.1.1 – Econometric Forecasting Models

Georgia Power's short-term forecasts are produced using econometric forecasting models, which estimate the relationships between economic and demographic variables and energy use. These models use ordinary least squares regression techniques.

E.1.2 – Load Management and Planning: Residential

The Residential LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the residential sector. This model was updated in 2020 by Applied Energy Group.

E.1.3 – Load Management and Planning: Commercial

The Commercial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the commercial sector. This model was updated in 2020 by Applied Energy Group.

E.1.4 – Load Management and Planning: Industrial

The Industrial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the industrial sector. This model was updated in 2020 by Applied Energy Group.

E.1.5 – Hourly Peak Demand Model

The hourly peak forecasting models produce projections of peak demand using forecasted class energy, historical class load shapes and corresponding weather, and a description of typical (normal) weather. These models use ordinary least squares regression techniques.

E.1.6 – Load Realization Model

The load realization model utilizes a probabilistic approach to evaluate the range and likelihood of future potential outcomes of the load growth from large new customers. The results from this model support the external adjustment applied to the baseline Commercial and Industrial load and energy forecasts.

E.1.7 – EnergyPlus/OpenStudio

EnergyPlus ™ models were used to predict hourly energy consumption in buildings based on construction characteristics, occupancy, orientation, local weather, and other attributes. EnergyPlus™ is DOE's open-source whole-building energy modeling (BEM) engine. OpenStudio is an open-source software development kit which aids model modification by presenting EnergyPlus inputs and outputs as a dynamic, object-oriented data format.

E.2 – Reliability

E.2.1 – SERVM

SERVM is a generation reliability model that is widely accepted across the industry and used for Resource Adequacy analyses. SERVM is an hourly, chronological model that utilizes Monte Carlo techniques. Random draws from unit historical failure and repair times are used to simulate unplanned outages. The model executes beginning with 1 A.M. on January 1, committing units, tracking available hydro energy, operating pumped storage units, considering weather-appropriate renewable output, making economic and reliability purchases from other entities in the region, calling interruptible load as needed, and, if necessary, curtailing firm load.

Evaluations are typically performed for multiple weather-years, multiple peak load forecast error assumptions, and multiple different start days for the year, resulting in hundreds of cases evaluated per simulation. Each case itself is processed multiple times using random unit outage draws with each iteration and the results of these iterations averaged together to develop a case-specific result. Each case has its own probabilistic weighting and is then averaged together with all cases to obtain a weighted average, expected result for the whole simulation. The Reserve Margin Study in Technical Appendix Volume 1 contains details regarding the number of simulations run to generate the Target Reserve Margin recommendations.

Useful information provided by SERVM includes (but is not limited to):

- Expected unserved energy, which is the amount of energy that cannot be served due to generating capacity shortages
- Loss of load expectation, which is the number of days per year in which firm load is not served
- Interruptible load, which is the number of times that interruptible load is called upon
- Production costs, which are the generation and purchase costs associated with serving load requirements throughout the year

E.3 – Expansion and Economic Analysis

E.3.1 – Aurora

Aurora is used to identify the optimal expansion plans and estimate marginal energy costs for use in various models and analyses.

<u>Expansion Plans</u>

Aurora employs a generation mix optimization module that includes the following major inputs: (1) future generating unit characteristics and capital cost; (2) the capital recovery rates necessary to recover investment cost; (3) capital cost escalation rates; and (4) a discount rate. Aurora is used to derive the least-cost expansion plan that minimizes total System cost considering all available combinations of capacity additions on a yearly basis that would satisfy the reserve margin constraints. The combination of alternatives with the smallest production and capital cost over the planning horizon is the least-cost plan.

The output of the model is used as the primary guide in developing the base case System expansion plan for the Retail Operating Companies. This System expansion plan identifies the capacity additions that serve as a guide for the type of capacity and energy resources that are most economical in a particular timeframe with the given assumptions. The output is also an input into the hourly production cost modeling, which is described below.

Marginal Energy Costs

Aurora is used to identify the least-cost commitment, dispatch and operation of the supply and storage components of the Company's fleet on an hourly basis. Among the key outputs are hourly projections of marginal energy cost throughout a 30-year planning period.

Other outputs include

- The Company's annual energy budget
- Marginal energy costs used in PRICEM, the RCB Framework applications, and elsewhere
- The SO_2 and NO_X marginal costs used in PRICEM.

E.3.2 – PRICEM

PRICEM is a spreadsheet-based marginal cost model designed by SCS to predict the change in costs and revenues attributable to changes in loads. PRICEM takes data from other major models and combines them in a single spreadsheet to provide quick, yet relatively detailed, evaluations of options. Data inputs are consistent with inputs to Aurora and as such are taken from: (1) revenue requirements stream from Standard Analysis Model ("SAM"); (2) marginal energy cost from Aurora; (3) Capacity equivalence factors from SERVM; and (4) technology cost assumptions.

PRICEM models the year with 864 load points and uses the peaker method, which is a technique allowing the total of generating capacity cost and energy cost to be estimated with peaking capacity and marginal energy cost. The peaker method provides a quick screening of many alternatives. Useful information that can be gathered from PRICEM includes:

- RIM – A NPV calculation of the total benefits and total costs over the life of the program; and
- Predictions of the amount of generating capacity needed to maintain System reliability after a change in interruptible or firm loads.

E.3.3 – SAM (Standard Analysis Model)

SAM is a financial analysis model used to convert capital expenditures into annual revenue requirements. It incorporates projections of the costs of capital, tax rates, and depreciation rates.

The useful information that can be gathered from SAM includes:

- Annual revenue requirements necessary to earn a return on and return of the investment
- NPV of revenue requirements
- Levelized fixed charge rates
- Economic carrying costs

SAM provides key calculations for numerous studies. It is used or has been used in: (1) calculating revenue requirements streams and economic carrying cost rates for PRICEM; and (2) calculating the economic carrying cost rates and NPV of revenue requirements for many studies, including for use in Aurora.

Attachment F – Hydroelectric Relicensing Schedule

In 1920, Congress passed the Federal Water Power Act, which gave the Federal Power Commission ("FPC"), FERC's predecessor, its original authority to license and regulate non-federal hydropower projects. FERC requires qualifying hydroelectric projects to have operating licenses. Licenses are typically issued as 40-year licenses. During the relicense process, hydroelectric resources undergo an environmental review in accordance with the National Environmental Policy Act. During the relicense process, the general public, federal and state agencies, non-governmental and special interest groups and other relicensing participants (e.g., local governments) provide input on the project and the FERC environmental review considers other statutes that affect hydropower regulation. Georgia Power is required to relicense existing operating licenses at the end of the license term and also ask for license amendments for modernization projects.

During relicensing, FERC may impose additional license conditions on Georgia Power based on input from relicensing participants. Outside of the FERC relicensing proceeding, FERC may require additional license conditions during a license term, including in some instances, requirements imposed by federal and state agencies. These requirements may result in loss of capacity and/or generation due to increased minimum flows, seasonal limits on generation, increased water withdrawals, limits on reservoir fluctuations, or dam removal. Additionally, reductions in peaking capability, ancillary services (e.g., voltage control), and operational flexibility could arise due to imposed ramping rates or modifications to current operational regimes. Finally, additional license requirements could come in the form of increased capital investment such as installation of facilities and equipment for environmental purposes (e.g., dissolved oxygen or fish passage facilities), installation and enhancement of recreational facilities, shoreline changes, habitat enhancements, monitoring and surveillance of environmental parameters, or replacement of capacity.

The following section highlights recent and upcoming relicensing proceedings for various Georgia Power hydro plants.

Hydro License Schedule		
Project	**License Expiration Date**	**Start Relicensing Per NOI/ILP**
Rocky Mountain	December 31, 2026	Filed December 10, 2021
Middle Chattahoochee (Goat Rock, Oliver, and North Highlands)	December 31, 2034	File between July 1, 2029 & December 31, 2029
Sinclair	April 30, 2036	File between October 30, 2030 & April 30, 2031
North Georgia (Burton, Nacoochee, Terrora, Tallulah Falls, Tugalo, and Yonah)	September 30, 2036	File between March 30, 2031 & September 30, 2031
Morgan Falls	February 28, 2039	File between August 28, 2033 & February 28, 2034
Flint River	October 31, 2039	File between April 30, 2034 & October 31, 2034
Bartletts Ferry	November 30, 2044	File between May 30, 2039 & November 30, 2039
Wallace Dam	May 31, 2060	File between November 30, 2054 & May 31, 2055
Lloyd Shoals	August 31, 2064	File between February 28, 2059 & August 31, 2059

F.1 – Wallace Dam

New License Issued June 1, 2020

Beginning in 2020, post-license enhancements required by the new FERC license began construction. These enhancements include an in-reservoir pure oxygen aeration injection system to improve dissolved oxygen in the plant discharge, an overhaul of existing recreation facilities, the addition of new bank fishing access areas for the public, and the implementation of mandatory conditions from the U. S. Forest Service, primarily consisting of recreation facility improvements on their lands within the FERC project boundary. Dissolved oxygen injection in the summer and U.S. Forest Service mandatory conditions will continue for the life of the FERC license.

F.2 – Lloyd Shoals Projects

New License Issued September 10, 2024

Beginning in 2025, post-license enhancements required by the new FERC license will begin construction. These enhancements include an overhaul of existing recreation facilities and the addition of two new public access areas.

F.3 – Langdale and Riverview Projects

Licenses Expired December 31, 2024 (FERC issued a 1-year extension of the existing license which previously expired December 31, 2023)

Georgia Power filed a Notice to Surrender these projects on December 18, 2018, and the Final Surrender Decommissioning Plan and Environmental Assessment were submitted to FERC in August 2022. Georgia Power must wait for the FERC Order approving the surrender before deconstruction can proceed.

F.4 – Rocky Mountain Pumped Storage Project (co-owned and jointly licensed with Oglethorpe Power)

License Expires December 31, 2026

A Notice of Intent to relicense the project was filed with FERC on December 10, 2021. Oglethorpe Power is leading the relicensing effort and filed the relicense application on December 6, 2024.

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Attachment G – Summary of the System Pooling Arrangement

G.1 – Introduction

Georgia Power is a member of the Southern Company Pool, which consists of the Operating Companies. The Operating Companies function as a single, integrated public-utility system through adherence to the Southern Company System Intercompany Interchange Contract ("IIC"), an agreement on file with FERC. SCS acts as agent for the Operating Companies in the administration of the IIC. The IIC provides a framework whereby the generating resources of the Operating Companies are operated in a coordinated and integrated fashion to economically serve their aggregate firm obligations, as well as to engage in shorter term transactions in the wholesale markets. Using traditional concepts of economic dispatch, the Pool deploys available generation to satisfy the aggregate obligations of the System at any given time in a reliable and economic fashion. The IIC also provides for coordinated planning between the Operating Companies and for the sharing of temporary surpluses and deficits of capacity. The IIC ensures that the after-the-fact accounting associated with joint System dispatch (energy) and reserve sharing (capacity) is handled in accordance with the principles set forth in that agreement. It should be noted that the coordinated planning process for the Retail Operating Companies is functionally separate from the planning process for Southern Power.

G.2 – Relationship of the Operating Companies under the IIC

The Southern Company Pool is a coordinated Pool, not a centralized Pool. Although the generating facilities of each Operating Company are committed to a centralized economic dispatch, each individual Operating Company retains the right and the responsibility for providing the generation and transmission facilities necessary to meet the requirements of its customers. Each Operating Company has a full executive management team to facilitate local execution and decision making that affect that Operating Company and its customers as well as its own board of directors to provide oversight. Each company is responsible for working with local regulators and adhering to the requirements of state law.

Accordingly, each Operating Company has its own distinct characteristics regarding types of generation and load. For example, Alabama Power, Georgia Power, and Southern Power bring hydro and nuclear generating capacity to the Pool, while Mississippi Power does not. Similarly, the load characteristics of the Operating Companies vary due to the types of customers each serve. The differing economies within each Operating Company territory and customer base lead to different load growth rates and load shapes for each Operating Company.

The IIC provides for an Operating Committee that consists of a designated representative from each Southern Operating Company and SCS, with the SCS representative acting as a non-voting Chairman. The functional separation of certain activities of Southern Power restricts the participation of its Operating Committee member in some matters (such as discussions and recommendations involving the coordinated planning of the Retail Operating Companies). All decisions of the Operating Committee must be unanimous.

G.3 – Interconnections

The Operating Companies are interconnected with 12 non-associated utilities through 61 different transmission facilities. These transmission lines are operated at voltages of 46 kV, 69 kV, 115 kV, 161 kV, 230 kV, and 500 kV, and include facilities that are operated normally open. The non-associated utilities with which the System is interconnected are shown in Table G.3.

Table G.3 – Non-Associated Utilities

Florida Power & Light Company (FPL)	Duke Energy Florida
JEA	City of Tallahassee
Duke Energy Corporation (Carolinas)	South Carolina Electric & Gas Company
Tennessee Valley Authority	South Carolina Public Service Authority
Entergy Corporation	Crisp County Power Commission
PowerSouth Energy Cooperative	South Mississippi Electric Power Association

G.4 – Basic Principles of the IIC

The basic principles of the IIC can be summarized as follows.

1. Each Operating Company submits its load and generation to the Pool for joint commitment and economic dispatch.
2. Energy Principles:
    a. Each Operating Company retains its lowest cost resources to serve its customers.
    b. An Operating Company's excess energy is next made available to the other Operating Companies to serve their customers if the cost of the Pool energy is less than the cost of energy from their own resources.
    c. Energy in excess of that necessary to serve the Operating Companies' customers is marketed by the Pool to the wholesale markets.
3. The IIC provides for coordinated planning among the Retail Operating Companies and for the sharing among all Operating Companies of temporary surpluses and deficits of capacity.
4. Under the IIC, each Operating Company shares in the benefits and pays its share of the costs resulting from their coordinated operations.

Participation in the Southern Company Pool provides benefits to the Operating Companies and to their customers. Pool participation not only enhances Georgia Power's ability to provide reliable, low-cost electric service to its customers but also to achieve economies of scale in any required investments. Benefits of Pool participation include:

- Staggering construction of new generating facilities so that each retail Operating Company can construct and install the optimum sized generating facilities while utilizing economies of scale;
- Sharing temporary surpluses and deficits of generating capacity that can arise as a result of coordinated planning or other circumstances (e.g., staggered construction schedules, variations in load patterns, load forecast uncertainties, etc.);

- Coordinating scheduled maintenance to provide greater flexibility, including major maintenance requiring relatively long unit outages, as well as mitigating the cost impact (to customers) of these required outages;
- Carrying a lower generation planning reserve margin (due primarily to System load diversity), which enables each Operating Company to have a lower investment in generating resources;
- Providing reliable service with shared operating reserve requirements (which puts downward pressure on fuel costs);
- Access to lower cost energy from other Operating Companies;
- Enhanced reliability of electric service through the use of transmission interconnections to provide backup service in case of emergencies as well as providing the ability to import lower cost energy when available; and
- Acting as a Pool (instead of individual Operating Companies) to identify shorter term purchase and sale opportunities in the wholesale markets that may be available from time to time.

G.5 – Basic Operation of the IIC

The concept of economic dispatch, which seeks to minimize the total System production cost, is one of the major benefits of the Pool. The generating assets of all the Operating Companies in the Pool are committed and dispatched as a common System without regard to the ownership of each generating facility. Subject to operational constraints and reliability considerations, the lowest cost generation assets are dispatched during each hour to meet the total needs of the customers of all the Operating Companies. The goal of this process is to ensure that the lowest cost energy is produced every hour. It also should be reiterated that each Operating Company retains its lowest cost generation to serve that Operating Company's customers.

The Pool also interfaces with the wholesale markets on behalf of the Operating Companies for both sales and purchases. When the Pool has excess power available, it will pursue wholesale sales opportunities for which there is a reasonable expectation that the transaction will result in positive net margin for the Operating Companies. There are two primary reasons for the Pool to seek purchase opportunities: (1) economics; and (2) reliability. The Pool will pursue purchase opportunities from the wholesale markets if such purchases are expected to be more economical than System resources (again, subject to operational constraints and System reliability). In the event the Pool experiences reliability challenges, then the Pool may seek purchases in response to such operating conditions.

G.6 – Reserve Sharing

As noted in the introduction, the IIC contains capacity provisions, commonly referred to as "reserve sharing," that provide for a sharing of temporary generating capacity surpluses and deficits that are a result of coordinated planning or other circumstances. As participants in the coordinated operation of the integrated electric system, each Operating Company enjoys the same level of service reliability. In any given month, however, one or more Operating Companies will have a temporary surplus or deficit of capacity relative to the overall level of actual System reserves. Consistent with the goal of sharing in the benefits and burdens of the coordinated and integrated electric system, the reserve sharing provisions of the IIC provide for the equitable allocation of such temporary surplus or deficit capacity. The resulting purchase and sale of capacity is transacted on a monthly basis.

Reserve sharing is determined by comparing each Operating Company's load responsibility with its respective capacity resources recognized through the coordinated planning process. The Operating Companies must own or purchase sufficient capacity (including capacity available for load service and that which is unavailable due to forced outage, partial outage, and maintenance outage) needed to reliably serve their respective load responsibilities. Capacity above that amount is considered reserve capacity, and each Operating Company is responsible for a portion of such reserve capacity based upon historical peak load ratios. If an Operating Company's reserve capacity is less than its reserve responsibility, that Operating Company will make reserve sharing payments under the IIC for the month.

Each Operating Company develops an annual charge (payments are based on monthly capacity worth) based upon the cost of its most recently installed or purchased peaking resource(s). The Operating Companies that are "selling" capacity to the Pool will receive a payment from the Pool based upon their respective capacity rates. The Operating Companies that are "buying" capacity from the Pool will make payments to the Pool based upon the weighted average of the capacity rates of the "selling" Operating Companies. In this way, all the buying Operating Companies pay the same composite cost in a given month for reserve sharing purposes. By definition, the amount by which one or more Operating Companies are "short" (make payments) will be equal to the amount by which one or more Operating Companies are "long" (receive payments).

G.7 – Energy Transactions

Energy transactions within the Pool are accounted for on an hour-to-hour basis, with the accounting occurring after-the-fact utilizing the actual flows among the Operating Companies.

The actual real-time operation of the System is based upon the concept of economic energy dispatch, which through online computer control assures that available generation is dispatched so as to choose the most economical generation available to serve the total System obligation at any given time. An adequate set of lowest-cost generating resources is committed in advance to meet the total System obligation, with due regard for generation requirements associated with service area protection, voltage control, unit protection, and other operating limitations considerations.

For billing purposes under the IIC, each Operating Company is deemed to have retained its lowest-cost energy resources (most notably hydro and nuclear) to serve its own territorial customers, plus whichever of its resources that may have been operating outside of economic dispatch for purposes of service area protection or voltage control. To the extent an Operating Company's generation exceeds its own load obligations, such energy is sold to the Pool under the IIC. If an Operating Company's generation is not equal to or greater than its own load obligations, the difference is purchased from the Pool. The energy rate for energy sold to or purchased from the Pool by each Operating Company is referred to as the Associated Interchange Energy Rate and represents the incremental System cost of serving the Operating Companies' aggregate firm obligations. Under the IIC, the determination of which Operating Companies are buying from and which are selling to the Pool is made on an hourly basis, and an invoice that accounts for these energy transactions is rendered monthly.

G.8 – Peak-Period Load Ratios

Peak-Period Load Ratios are utilized in the allocation of certain energy and capacity transactions by the Pool with non-associated systems, hydro regulation energy losses, increases in cost due to hydro regulation, and other allocations provided for in the IIC and the Manual to the IIC.

The Peak-Period Load Ratios for each contract year are based upon the prior year's actual peak-period energy in the months of June, July, and August for each Operating Company. The peak period is defined to be the 14 hours between 7:00 a.m. and 9:00 p.m. of each weekday, excluding holidays. The System peak-period energy is equal to the sum of all the Operating Companies' peak-period energy.

The Peak-Period Load Ratios are determined by dividing each Operating Company's summation of the June, July, and August actual weekday peak-period energy loads by the total System June, July, and August actual weekday peak-period energy loads.

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Attachment H – Research Activities

Georgia Power, as a subsidiary of Southern Company, is involved in a range of research activities and programs to facilitate the development of new technologies with the potential to benefit Georgia Power's customers. Southern Company is an industry leader in the R&D of emerging energy technologies and, on behalf of the Operating Companies, manages a diverse research portfolio. This ensures Southern Company and its subsidiaries have the capabilities and knowledge to successfully deploy technologies to meet customers' energy needs today and in the future. Current R&D activities are organized into a comprehensive strategy designed to meet four primary needs for Southern Company, its Operating Companies, and its customers. The R&D strategy is organized into four strategic aspirations, as outline below, that define the top-level focus areas within the R&D portfolio. Each research program develops a specific portfolio strategy in support of these aspirations, as well as near-term objectives to ensure consistency between long-term strategy and near-term tactics. The R&D organization operates in teams according to subject matter expertise including Generation Fleet; Advanced Energy Systems; Carbon Capture, Storage, and Utilization; Energy End-Use; Power Delivery; and Renewables, Storage and Distributed Generation. The R&D program teams work collaboratively on projects that are directly connected to each specific research objectives to deliver the R&D strategy in an efficient and aligned manner. SCS-lead R&D projects within each of programs may be specific to a particular Operating Company.

Strategic Aspiration 1: Develop a sustainable energy future through customer-focused, cost-effective solutions.

- Modernize the domestic nuclear industry landscape to enable broad deployment of advanced nuclear technology in the 2030s. As a part of this effort, R&D will support the development and implementation of a new, risk-informed and performance-based NRC licensing pathway by mid-2020s for use regulating advanced reactors. R&D will support the establishment of critical infrastructure and supply chains, including advanced reactor fuel, for advanced reactor demonstrations. Additionally, R&D will explore sustainable technical options for nuclear fuel life cycles.

- Develop low-carbon generating options. This area will focus on a broad range of generating technologies including wind, advanced nuclear, hydrogen, and oxy-combustion technologies. Included efforts will work to develop low-cost renewables that are predictable, dispatchable, and sustainable. Work on advanced power cycles will include efforts to assess, scale up, demonstrate, and validate novel power cycles. Advanced nuclear work will continue with demonstrations of various aspects of TerraPower's Molten Chloride Fast Reactor technology. Additional research will examine the potential role of hydrogen for power production.

- Advance carbon capture for power generating technologies through improved flexibility and integration. The R&D organization will continue to operate the DOE-sponsored National Carbon Capture Center in Wilsonville, AL to advance technologies to reduce GHG emissions from natural gas- and coal-based power plants.

- Continue to investigate relevant carbon capture technologies to develop cost models and front-end engineering and design ("FEED") studies to develop cost models for deployment within natural gas generating plants.

- Engage in additional efforts to reduce atmospheric carbon through negative emissions technology. The R&D team will perform cost/benefit analysis of DAC and natural systems technologies for carbon-negative approaches.

- Enable the dispatchability, predictability, and sustainability of renewables. The R&D team will work to develop technologies that will allow renewable to be deployed similar to fossil fuel plants. Through development of improved forecasting tools, the team will work to reduce impact of renewable variability.

- Demonstrate CO_2 storage and utilization concepts to offset cost to the customer. Research will continue to demonstrate the feasibility of CO_2 storage at a commercial scale. Included scope will support the development of potential storage business models and perform key site assessments within the service territory.

Strategic Aspiration 2: Provide delivery, storage, and distributed generating solutions that meet reliability, resiliency, and flexibility needs.

- Continue to demonstrate potential energy storage technologies at relevant scales, including hydrogen storage, thermal energy storage, and flow battery concepts to enable low-carbon storage with a sustainable life cycle.

- Enhance System reliability and resilience while maintaining affordable energy to customers. This research includes a strategic focus on electromagnetic pulse ("EMP")/geomagnetic disturbance ("GMD") resiliency and driving efficiency and flexibility with digital applications. Work will focus on improving the ability for the grid to withstand and respond to major threats and extreme events from both man-made and natural domains. R&D will leverage real-time digital simulation of power grid and network communications to develop alternative approaches to detect, and withstand, and respond to cyber-attack utilizing grid information. Additionally, to drive efficiency in power grid management, restoration, and security, R&D will work to develop unmanned inspection technologies.

- Develop and demonstrate digital substation technologies that improve reliability and resiliency while lowering both capital cost and deployment time of new substations.

- Utilize grid data to enhance operational efficiencies by performing advanced analytics using machine learning combined with high powered simulation tools. Work will utilize data analytics and AI to predict, detect, and mitigate impending grid disturbances. R&D will develop robust modeling and simulation techniques to address increased complexities on the grid that facilitate efficient analyses of offline and real-time scenarios including hardware-in-the-loop applications. Enhanced digital worker applications will be leveraged to address a rapidly changing workforce and increased regulatory and compliance requirements, while taking advantage of new all-digital design processes and their potential integration with digital substation. Finally, holistic power quality monitoring and automated data analysis will maintain superior power quality in the face of increasing grid complexity, delivering new insights and operational efficiencies.

- Enable the necessary grid reliability and flexibility to accommodate changing generation sources and increasing electrification in a net-zero market. R&D will support the development of multiple enabling technologies for deployment of DERMS platforms including power flow control devices, expanded fiber optic infrastructure for DER integration, and scalable communications systems for edge of grid awareness, advanced circuit protection to match the speed of inverter-based resources, and maintaining superior customer power quality in the presence of widespread inverter-based resources. These technologies will culminate in a System-level DERMS Pilot Demonstration.

Strategic Aspiration 3: Develop end use technologies that support expanding customer needs.

- Support the advancement of the transportation sector through decarbonization technologies, enabling infrastructure, and identification of new business opportunities. This work will focus on a broad range of vehicle platforms including light-duty passenger vehicles, medium- and heavy-duty vehicles, bus, forklift, and off-road applications. Work will examine and demonstrate enabling technologies for low-carbon transportation.

- Develop key technologies to leverage load flexibility allowing for improved planning, demand-side management, and peak load reduction. These technologies include energy efficiency, advanced load controls, and load aggregation methodologies.

- Support customer needs for sustainability and resiliency through industrial process solutions. This research area will develop industrial sector decarbonization strategies and roadmaps for industrial customers. Technology focus areas will include zero-carbon energy carriers, process heat technologies, and technologies to retrofit heavy-emitting industry sectors.

- Perform assessment and opportunity analysis of large data analytics technologies and applications. Work will leverage advanced data analytics, AI and Machine Intelligence, for insight into customer needs to advance customer targeting, energy efficiency, and other business objectives. A holistic value assessment will be developed, utilizing internal and external data repositories to identify compelling use cases.

Strategic Aspiration 4: Advance the existing generating fleet through minimizing cost and improving efficiency.

- Develop solutions to address environmental risks and look for business development opportunities in the process. This research will focus on improving and developing economical and technically viable solutions to support groundwater corrective action requirements associated with ash pond closures, water treatment requirements associated with ash pond closures and ELG compliance, and advancements in water conservation technologies that can be employed at Company facilities.

- Research the development of technologies to increase the overall amount of CCRs harvested from ponds for beneficial use projects, as well as development of specific beneficial use projects, such as separation of rare earth elements from CCRs.

- Develop cross-cutting technologies that will lead to a reduction in O&M, an increase in flexibility, and/or an increase in resiliency in the transforming fleet. R&D will work to fully demonstrate a digital plant concept leading to development of Advanced Controls and AI, allowing gas plants to reduce work force and transition to almost complete conditioned based maintenance.

Attachment I – Acronyms, Abbreviations, and Terminology

111 GHG Rules	EPA's 111 Greenhouse Gas Rules
111-HG0	High gas, zero-dollar carbon with 111 GHG Rules
111-MG0	Moderate gas, zero-dollar carbon with 111 GHG Rules
111-MG50	Moderate gas, zero-dollar carbon with 111 GHG Rules
2019 IRP Order	Commission Order on July 29, 2019, approving the 2019 IRP with modifications
2022 IRP Order	Order Adopting Stipulation, Docket No. 44160 (July 29, 2022)
2022 Rate Case Order	Order Adopting Settlement as Modified, Docket No. 44280 (December 30, 2022)
2023 IRP Update Order	Order Adopting Stipulated Agreement, Docket No. 55378 (March 26, 2024)
2025 DSM Application	Application for the Certification, Decertification, and Amended Demand-Side Management Plan, Docket No. 56003
AAR	Ambient-Adjusted Rating
AC	Alternating Current
AEO	Annual Energy Outlook
AFB	Air Force Base
AI	Artificial Intelligence
APC	Alabama Power Company
ARO	Asset Retirement Obligation
Aurora	Capacity expansion and production cost model. See model description in E.3.1.
B25 or B2025	Budget 2025
BESS	Battery energy storage system. A system that stores energy for later use.
Blackstart Resources	Defined by the NERC Reliability Standards[1] as "a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan
BOP	Balance of plant
BTM	Behind the meter
C&I	Commercial & Industrial
CARES	Clean And Renewable Energy Subscription. A subscription program for renewable energy.
CC	Combined Cycle. A type of power plant that uses both gas and steam turbines to generate electricity.
CCR	Coal Combustion Residuals

CCR ARO	Coal Combustion Residuals Asset Retirement Obligation
CCS	Carbon Capture and Sequestration. A technology to capture and store carbon dioxide emissions from power plants and industrial sources.
CCSP	Customer-Connected Solar Program
CIR	Customer Identified Resource
CL	Curtailable Load
CO_2	Carbon dioxide
COD	Commercial Operation Date
Commission	Georgia Public Service Commission
Company	Georgia Power Company
CRSP	Customer Renewable Supply Procurement. A program for procuring renewable energy for customers.
CS	Customer-Sited. Refers to energy resources located at the customer's site.
CSE	Cost of Saved Energy
CT	Combustion Turbine. A type of gas turbine used for electricity generation.
DAC	Direct Air Capture. A technology to capture carbon dioxide directly from the air.
DCL	DER Colocation Program
DCO	DER Customer-Owned Program
DEF	Duke Energy Florida
DER	Distributed Energy Resource. Small-scale units of local generation connected to the grid at distribution level.
DER Customer Program Pilot	Customer-focused program that addresses the emerging resilience needs of commercial and industrial customers through dispatchable DER-based solutions, while also providing demand response value to the benefit of all customers
DERMS	Distributed Energy Resource Management System. A system to manage distributed energy resources.
DG	Distributed Generation
DLR	Dynamic Line Rating
DOE	Department of Energy
DPEC	Demand Plus Energy Credit
DR	Demand Response
DRC-1	Demand Response Credit Tariff
DSM	Demand-Side Management
DSMWG	Demand-Side Management Working Group
DSOs	Demand-side options. Strategies to reduce energy consumption through various programs and incentives.
EASE	Energy Assistance for Savings and Efficiency
ECCR	Environmental Compliance Cost Recovery

ECS	Environmental Compliance Strategy. A strategy to comply with environmental laws and regulations.
EIA	Energy Information Administration. A U.S. government agency responsible for collecting and analyzing energy data.
EL	Emissions Limit scenario
ELCC	Effective Load Carrying Capability. A measure of the contribution of a power source to system reliability.
ELG	Effluent Limitations Guidelines
EMP	Electromagnetic Pulse. A burst of electromagnetic radiation that can disrupt electronic equipment and infrastructure.
EnergyUnited	EnergyUnited Electric Membership Corporation
EOO	Energy Offset Only
EPA	Environmental Protection Agency. A federal agency tasked with protecting human health and the environment.
EPC	Engineering, procurement, and construction
EPD	Environmental Protection Division
EPRI	Electric Power Research Institute. An independent, nonprofit organization conducting research and development in the electricity sector.
EPU	Extended Power Uprate
ER	Environmental Report
ESS	Energy Storage Systems
ET	Electric Transportation
EV	Electric Vehicle
FACTS	Flexible AC transmission systems
FEED	Front-End Engineering and Design. A project development phase that includes detailed engineering and design work.
FERC	Federal Energy Regulatory Commission. An independent agency that regulates the interstate transmission of electricity, natural gas, and oil.
Flint EMC	Flint Electric Membership Corporation
FPC	Federal Power Commission
FPA	Federal Power Act
FPL	Florida Power and Light
FTM	Front of the meter
Georgia Power	Georgia Power Company
GETs	Grid-Enhancing Technologies
GEFA	Georgia Environmental Finance Authority
GHG	Greenhouse Gas. Gases that trap heat in the atmosphere.
GMD	Geomagnetic Disturbance. A temporary disturbance of the Earth's magnetosphere caused by solar wind.
GRIP	Grid Resilience and Innovation Partnerships
GTC	Georgia Transmission Corporation
GW	Gigawatt

HG0	High gas, zero-dollar carbon
Hydro	Hydroelectric
IE	Independent Evaluator
IIC	Intercompany Interchange Contract
IIJA	Infrastructure Investment and Jobs Act. A U.S. federal law focused on infrastructure investment, including energy infrastructure.
IRA	Inflation Reduction Act. A U.S. federal law aimed at reducing inflation, which includes provisions for renewable energy and energy efficiency.
IRP	Integrated Resource Plan. A long-term plan to meet forecasted energy demand with a mix of supply-side and demand-side resources.
IRP Act	Integrated Resource Planning Act of 1991
ITC	Investment Tax Credits
ITS	Integrated Transmission System
ITS Participants	Georgia Power, Georgia Transmission Corporation, MEAG Power, and Dalton Utilities
JEA	Jacksonville Electric Authority
kW	Kilowatt
kWh	Kilowatt Hour
LG0	Low gas, zero-dollar carbon
LoadMAP	Load Management Analysis and Planning
LOLE	Loss of Load Expectation. A reliability metric representing the expected number of days per year that the system's load will exceed available generation capacity.
MARTA	Metropolitan Atlanta Rapid Transit Authority
MATS	Mercury and Air Toxics Standards
MDA	Market Differential Adjustment
MEAG Power	Municipal Electric Authority of Georgia
MG0	Moderate gas, zero-dollar carbon
MG20	Moderate gas, twenty-dollar carbon
MG50	Moderate gas, fifty-dollar carbon
MPC	Mississippi Power Company
MUSH	Municipalities, universities, schools, and hospitals
MW	Megawatt
MWh	Megawatt hour
NEMS	National Energy Modeling System. A computer-based, energy-economy modeling system of the U.S. energy economy.
NERC	North American Electric Reliability Council
NGCC	Natural Gas Combined Cycle
NGCC with CCS	Natural Gas Combined Cycle with Carbon Capture and Sequestration

NOI	Notice of Intent. A formal declaration of intent to participate in a program or project.
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NWA	Non-wires alternative
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
OEM	Original equipment manufacturer
Operating Companies	Georgia Power Company, Alabama Power Company, Mississippi Power Company, and Southern Power Company
PACT	Program Administrator Cost Test
PIA	Public Interest Advocacy
POI	Point of Interconnection
Pool	The Operating Companies operate their respective electric generating facilities and conduct their system operations
PPAs	Power Purchase Agreements
PRICEM	Profitability Reliability Incremental Cost Evaluation Model - See model description in E.3.2.
PT	Participants Test
PTC	Production Tax Credits
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QF	Qualifying Facilities. Small power producers or cogenerators that meet certain criteria under PURPA
R&D	Research and Development
R3	Retail REC Retirement
RAS-1	Resiliency Asset Service
RCB	Renewable Cost Benefit
RCOD	Required Commercial Operation Date
REC	Renewable Energy Credit. A certificate representing the environmental benefits of generating one megawatt-hour of electricity from renewable sources.
Reconsideration Rule	2020 ELG Reconsideration Rule
REDI	Renewable Energy Development Initiative
Resource Adequacy	The ability of supply-side and demand-side resources to meet electrical demand and maintain an appropriate level of system reliability
Retail Operating Companies	Georgia Power Company, Alabama Power Company, and Mississippi Power Company
RFP	Request for Proposals. A document soliciting proposals from potential suppliers or contractors.
RIM	Rate Impact Measure
RNR	Renewable and Non-Renewable

SAM	Standard Analysis Model
SCR	Selective Catalytic Reduction
SCS	Southern Company Services
SCT	Societal Cost Test
SEIA	Solar Energy Industries Association
SERC	Southeastern Electric Reliability Council. A group of electric utilities coordinating operations to maintain system reliability in the Southeastern U.S.
SERVM	Strategic Energy Risk Evaluation Model
SLR	Subsequent License Renewal
SLRA	SLR Application
Southern Company	Parent company of Georgia Power Company, Alabama Power Company, Mississippi Power Company, Southern Power Company, and Southern Company Gas
STATCOM	Static synchronous compensator
System	Southern Company System
TRM	Target reserve margin. The generation capacity required above the forecasted peak demand
TRC	Total Resource Cost
U.S.	United States
US	Utility Scale
V2X	Vehicle-to-Everything
VIP	Voluntary Incentives Program
Vogtle Prudence Order	Commission's Order Adopting Stipulation in the Vogtle Prudency Proceeding in Docket No. 29849
Wholesale Action Plan	Order approving Georgia Power Company's Proposal to Offer Certain Wholesale Capacity Blocks to Retail Jurisdiction, Docket No. 26550-U (July 30, 2008)