STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's 2022 Integrated Resource Plan	)))	**Docket No. 44160**
In the Matter of: Georgia Power Company's 2022 Application for the Certification, Decertification, and Amended Demand Side Plan	))))	**Docket No. 44161**

Stipulation

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2022 Integrated Resource Plan (the "2022 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2022 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

Supply Side Plan

1. The 2022 IRP is approved as filed unless amended by this Stipulation.

2. Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1 shall be decertified and retired by August 31, 2022.

3. Plant Scherer Unit 3, Plant Gaston Units 1-4, and Plant Gaston Unit A shall be decertified and retired by December 31, 2028.

4. The Company's Unit Retirement Study in this case supports the retirement of Bowen Units 1-2. PIA Staff analysis found that the retirement of Bowen Units 1-2 is a close call. Stipulating Parties agree that the decision to retire Bowen Units 1-2 and by when is a policy decision for the Commission. As such, provided that

retirement is contingent upon completion of the necessary transmission system improvements identified in Technical Appendix Volume I of the 2022 IRP, the Stipulating parties agree that it is appropriate for the Commission to determine as a matter of policy, when, between December 31, 2027 and December 31, 2035, Bowen Units 1-2 should be retired. The units may be retired separately or together. Should either or both units operate beyond December 31, 2027, all reasonable and prudent costs associated with their continued reliable operation will be recovered by the Company.

5. The Company's plan to install Effluent Limitation Guidelines ("ELG") controls for Plant Bowen Units 3-4 (and, subject to the retirement decision outlined in Paragraph 4, Plant Bowen Units 1-2), and Plant Scherer Units 1-2 is approved as part of the Company's Environmental Compliance Strategy ("ECS"), as discussed further in Paragraph 15.

6. The Stipulating Parties agree that the Commission should grant the certificate of public convenience and necessity for the long-term power purchase agreements ("PPA") for Plant Wansley Unit 7, Plant Dahlberg Units 2 & 6, Plant Harris Unit 2, Plant Dahlberg Units 1, 3 & 5, Plant Monroe Units 1-2, and Plant Dahlberg Units 8-10, as requested in this case.

7. The additional sum for the procurement of the long-term capacity PPAs approved in Paragraph 6 will be set at $3/kW-yr. Adoption of this additional sum is not precedent setting, and no Stipulating Party is foreclosed from proposing an alternative additional sum in a future capacity procurement.

8. The transmission projects necessary to accommodate the retirements approved in the 2022 IRP are approved. This approval includes the transmission projects (or their equivalent solutions) identified in the Selected Supporting Information section of Technical Appendix Volume 1.

9. The Company will develop and file an annual transmission update report with the status of each transmission project in the Company's Selected Supporting Information contained within Technical Appendix Volume 1 and the Unit Retirement Study contained within Technical Appendix Volume 2 of the 2022 IRP. The report will be filed on or before February 28 of each year and will include the schedule, status and budget for each active and future transmission project. For each transmission project, the Company will identify alternative solutions considered and the associated costs and benefits of the alternatives. In its 1st annual transmission update report, the Company should reconcile the

projects it plans to perform between the Selected Supporting information list, and the Unit Retirement Study list. The Company will continue to investigate and consider the use of emerging grid technologies as described in Technical Appendix Volume 3 of the 2022 IRP.

10. The Company is approved to proceed with the North Georgia Reliability & Resilience Action Plan ("North Georgia Reliability Plan") as defined in Chapter 12 of the 2022 IRP except for projects from the Utility Scale RFP being limited to projects sited in north Georgia. The Company will work with Commission Staff to develop a process that facilitates the development of renewable resources in north Georgia. The Company agrees to meet semi-annually with Commission Staff to provide updates regarding progress on the North Georgia Reliability Plan and the impacts of a future retirement of Plant Bowen Units 3-4. These meetings will include updates on strategic transmission projects developed by ITS Participants to allow for retirement of Plant Bowen Units 3-4 and the continued development of renewable resources in Georgia.

11. Staff reserves the right to challenge the timing of transmission capital investments during 2023 - 2025 in the upcoming 2022 rate case.

12. The Stipulating parties agree that the Company's request to develop, own, and operate 1,000 MW of energy storage system ("ESS") projects by 2030 is not approved in this IRP. While the Stipulating Parties acknowledge the potential value of ESS to the reliability of the electric system, the costs of ESS should be taken into account relative to any benefits provided.

13. The Company is provisionally authorized to develop, own, and operate the McGrau Ford Battery Facility (the "McGrau Ford Project"). The Company will be required to provide the final McGrau Ford Engineering Procurement and Construction ("EPC") agreement (or agreements if more than one) to the Commission prior to undertaking procurement for or construction of the McGrau Ford Project. Following the Company's provision of the EPC agreement to the Commission, the Commission will determine whether to proceed with the McGrau Ford Project and provide a deemed certified amount for the McGrau Ford Project. If the Company exceeds the deemed certified amount, the Company has the burden of showing that such costs were prudently incurred. The Company will also file quarterly construction monitoring reports from the date construction begins through the date of commercial operation.

14. In the absence of a Commission approved winter target reserve margin ("TRM"), and because resource additions are not anticipated during the 3-year IRP period using either the Staff's proposed 24.5% or the Company's proposed 26%, the Stipulating Parties agree that the Company will continue to use the System winter TRM of 26% for seasonal planning purposes until such time as a winter TRM is agreed to between PIA Staff and the Company and approved by the Commission. There is no requirement for the Commission to act upon the winter TRM request at this time. The Company may propose resource additions in the next IRP, if needed, to meet winter TRM, and the Commission can determine at that time the appropriate winter TRM and whether such additional capacity is needed. Use of the 26% winter TRM for planning purposes is not an endorsement by the Stipulating Parties of that TRM, and no Stipulating Party is foreclosed from proposing an alternative winter TRM in a future case.

15. The Company's ECS is approved as updated in the 2022 IRP. This includes specific approval of the updates to the Company's plans to address coal combustion residuals ("CCR") at the Company's ash ponds and landfills. Stipulating Parties acknowledge that projected CCR compliance costs have been reviewed in this case, that the Commission is not approving any costs, and that it is not necessary for the Commission to approve a specific budget for CCR compliance in this IRP proceeding. The Parties agree that the Company will seek recovery of such costs in its 2022 base rate case. PIA Staff reserves the right to challenge the Company's request for recovery in the 2022 base rate case, including, but not limited to, the amount to be recovered as reasonable and prudent, the period over which costs are recovered and the method by which they are recovered. The Company will continue to provide semi-annual reports to the Commission. The Company will also provide notice to the Commission within 30 days of any determination by the Environmental Protection Division that would alter the Company's current plan from closing certain ash ponds in place. Additionally, the Company will continue to file the ECS annually with the Commission no later than March 31st of each year.

16. Once the Company's CCR beneficial reuse RFP process has been completed, the Company will file a final report on the results of the RFP with the Commission. The report will include updates, if needed, to the Company's cost benefit analysis that provides economic justification of the Company's beneficial reuse plan.

17. The detailed cost information that supports the measures taken to comply with the existing government-imposed environmental mandates necessary for the Company to implement its ECS as presented in Technical Appendix Volume 2

and Environmental Compliance Cost Recovery ("ECCR") and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 1 of the 2022 IRP, as supplemented through data requests, have been reviewed in this proceeding and are acknowledged. Recovery of ECS plan costs will be determined by the Commission in a future rate case. PIA Staff reserves the right to challenge the Company's request for recovery of ECS plan costs in the 2022 base rate case, including, but not limited to, the amount to be recovered as reasonable and prudent, the period over which costs are recovered and the method by which they are recovered.

18. The Company will conduct an all-source Request For Proposal ("RFP") for capacity needed in the 2029 – 2031 period to address the expiration of capacity PPAs during 2029 – 2031 and any generation retirements. Specific RFP guidelines, including resource eligibility requirements, will be approved by the Commission in accordance with the Commission's RFP process.

19. The Company shall procure 2,100 MW alternating current ("AC") of new utility scale renewable resources, which are defined as projects greater than 6 MW AC in size. The Company will procure these resources for Commercial and Industrial customer subscriptions through the Clean and Renewable Energy Subscription ("CARES") Program through the carveout MW amounts as proposed in the Company's filing. Final program and tariff design for individual CARES carveouts will be finalized after the 2022 IRP through negotiations with members of the Commercial Group, members of the Georgia Association of Manufacturers, The Georgia Coalition of Local Governments, and Commission Staff. The Utility Scale procurement will take place through two separate RFPs. The first RFP is expected to be issued in 2023 and will target 1,050 MW of renewable resources with proposed commercial operation dates of 2026 or 2027. A second RFP is expected to be issued in 2025, seeking to procure the remaining MW needed to reach the 2,100 MW target procurement, with proposed commercial operation dates of 2028 or 2029. Any resources not fully subscribed through the CARES Program will serve all retail customers.

The following will be included in the fuel clause and recovered through the Fuel Cost Recovery Mechanism ("FCR"): (i) all revenues collected through the CARES Program, with the exception of the additional sum as described in Paragraph 23, and (ii) all appropriate costs that are not recovered elsewhere by the Company and are incurred in connection with the procurement of the aforementioned resources for subscription in the CARES Program. CARES Program costs and revenues which are to be included in FCR include but are not limited to the following: (i) the costs to implement and administer the CARES Program, (ii) the bid fees collected in connection with the CARES Program, the fees collected from subscribing customers, and (iii) the PPA that are executed to supply the CARES Program, including any payments for PPAs made by participants.

20. The Company's evaluation and selection of renewable resources based on the best cost provided to customers is approved for future renewable procurements. The Company will work with PIA Staff and the Independent Evaluator ("IE") to determine the exact criteria and methods of evaluating, ranking, and selecting bids through the aforementioned best cost methodology as part of the Commission-approved RFP process.

21. For future Utility Scale renewable RFPs, all renewable projects, both with and without storage devices, will be required to be operated on Automatic Generation Control ("AGC"), and the Company will consider new use cases that flexibly utilize the coupled energy storage devices with AGC control. The Company and Staff shall determine the appropriate methodology to value such resources before the next Utility Scale renewable RFP is released.

22. The Company shall issue an RFP to procure energy from up to 200 MW AC of distributed generation solar resources ("DG"), which are defined as being greater than 250 kW but not more than 6 MW AC in size. It will do so through two solicitation periods, each seeking 100 MW AC of DG solar resources. The first solicitation is expected to occur in 2023 with proposed commercial operation dates of 2024. The second solicitation is expected to occur in 2024 with a proposed commercial operation dates of 2025. The projects will be procured using the Company's best cost procurement approach which will be agreed upon by the Company and Staff and approved by the Commission during the RFP process. Contract terms for resulting DG projects will be for up to 35 years. DG projects must interconnect to Georgia Power's distribution system. Bid and winners' fees will be set to recover the total cost of procurement for the RFP solicitations. All revenues collected, and all appropriate costs not recovered elsewhere by the Company, which are incurred in connection with the procurement of the aforementioned DG resources shall be included in the fuel clause and recovered through the FCR.

23. The additional sum for both the utility scale resources procured pursuant to Paragraph 19 above and the DG resources in Paragraph 22 shall be set at a levelized additional sum of \$4.00/kW-yr. Adoption of this additional sum is not precedent setting, and no Stipulating Party is foreclosed from proposing an alternative additional sum in a future renewable procurement.

24. The Hosting Capacity Tool is approved and will be modified as follows. The Hosting Capacity Tool will be made available year-round pursuant to a registration process that requires the signing of a confidentiality and nondisclosure agreement. The Company will work to update the Hosting Capacity Tool semi-annually, but initial efforts will be focused on an annual update for the Company's more than 2,300 feeders. The hosting capacity analysis shall also reflect the available solar capacity based on Minimum Daytime Loading or Coincident Peak limitations at the breaker, but is not intended to be a replacement for the Company's required interconnection study process. Administrative costs associated with the Hosting Capacity Tool will be recovered through the FCR.

25. The Company and Staff will initiate a review of Georgia Power's DG interconnection process prior to the next DG RFP to consider modifications and to establish a distribution interconnection cost matrix.

26. The Existing Resource Retail REC Retirement ("R3") Program is approved. The Company agrees to file quarterly participation reports that provide the amount of MW and the number of customers that have subscribed to the R3 program.

27. The Company's Community Solar Program proposed in the 2022 IRP is approved except for the Company's requests to increase the residential block charge to $27.99 and to set the commercial option at $29.99/month, which will be considered in the 2022 Rate Case. This approval includes the Income-Qualified Community Solar Pilot. The Company agrees to file quarterly participation reports that provide the number of customers and subscription blocks that have been subscribed to for each portion of the Community Solar program.

28. The Company's Flex REC Program and modification to the Simple Solar Program proposed in the 2022 IRP are approved except for revisions to the rates for this program, which will be considered in the Company's 2022 Rate Case. The Company agrees to file with the Commission, for informational purposes, the negotiated contracts for the Economic Development Flex REC option once they are executed.

29. The Renewable Cost Benefit Framework ("RCB") and the Renewable Integration Study ("RIS") filed in this case are approved for future renewable procurements with the three following modifications. First, the Stipulating Parties agree to use the incremental renewable integration costs approach when determining the renewable integration costs for future renewable procurements until a future study

is completed and approved. This assumption will be $1.93/MWh for solar resources up to the 2,300 MW of new renewables approved in this IRP. Staff and the Company will meet after the 2022 IRP concludes to address the other methodological differences discussed in Section 4 of Staff's direct testimony and then file a report, including any proposed methodology changes by either party resulting from the discussions, with the Commission for approval by June 30, 2023. In addition, the Company and Staff will discuss Staff's suggestion to modify the Deferred Generation Capacity Cost component to use the economic carrying costs ("ECC") of a combined cycle unit instead of a combustion turbine. Second, for IRP-approved procurements for which RECs are conveyed, the Stipulating Parties agree to include a REC component within the RCB Framework. Staff and the Company will meet after the 2022 IRP concludes to determine how to appropriately value the REC component and then bring the method to the Commission for approval. Third, the Stipulating Parties also agree to use the effective load carrying capability ("ELCC") method when determining capacity value for procurement activities. The Stipulating Parties agree that resolution of this issue does not limit the positions that either Party can take regarding the RCB and RIS costs in a future proceeding where modifications to the RCB and RIS may be considered.

30. In the next IRP, and any upcoming RFPs issued before the next IRP, the Company agrees to use the ELCC methodology to determine the renewable resource capacity values.

31. The Stipulating Parties agree that the Blocks 2-4 and Blocks 5&6 wholesale block capacity offer should be rejected by the Commission. The offer by the Company, and the rejection by the Commission fulfills the Company's requirements under Docket No. 26550 to offer this capacity to the retail jurisdiction. The Company may, at its own discretion, offer such capacity within the wholesale market or to the retail jurisdiction in a future capacity solicitation or through other permissible avenues. In addition, the Commission should deem the Company's obligations to make any wholesale offer under Docket No. 26550 consisting of Plant Gaston Units 1-4 and A and Plant Scherer Unit 3 satisfied, thereby releasing the Company from any further requirement to offer wholesale capacity from these units to the retail jurisdiction prior to any remarketing of that capacity.

32. The Stipulating Parties agree to approve the modernization of Plant Sinclair and Plant Burton. The proposal to include Plant North Highlands in the Company's hydro-electric modernization plan is not approved at this time. Plant Sinclair and Plant Burton shall be added to the Company's semi-annual reporting on its hydro

modernization efforts. All future hydro modernization requests will include a cost-benefit analysis and economic comparison of the alternatives to modernization. The Company will provide such an analysis for Plant Burton in its 2025 IRP filing.

33. The DER Customer Program proposed to be implemented through the Demand Response Credit Tariff ("DRC-1") and the Resilience Asset Service Tariff ("RAST-1") will be approved on a pilot basis with an overall cap of 250 MW. The tariffs and associated contract terms and conditions shall be designed in a manner that will eliminate, to the extent reasonably possible, any potential that non-participating customers will be harmed. Within 4 months following the issuance of the Commission's Order approving this Stipulation, the Company will collaborate with the Commercial Group and Staff on the development of these elements in the DER pilot program tariffs. Following this collaboration, the Company shall file the DRC-1 and RAST-1 tariffs for Commission approval. The Stipulating Parties preserve their right to argue for modifications to the tariffs when they are filed for approval.

34. The DER local reliability and constraints pilot projects at Mansfield, Savannah, Moreland Way and Lake Sinclair are approved. The Company shall file semi-annual update reports for the first five years of the pilot projects.

35. The capital and O&M costs for the Tall Wind demonstration project (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 1, are approved. The Company agrees to notice the Commission should it determine that the budget for the Tall Wind project will exceed the budgeted amount presented in the 2022 IRP. The Company shall file semi-annual update reports through the life of the demonstration project.

36. The integrated Hydrogen Microgrid pilot project as set out in Selected Supporting Information section of Technical Appendix Volume 1 is approved. The Company shall file quarterly update reports through the life of the pilot project.

37. The remaining net book values of Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1 shall be reclassified as regulatory assets and the Company shall provide for amortization expense at a rate equal to the unit's depreciation rate approved in the Company's 2019 base rate case. The timing of recovery of the remaining balances of these regulatory assets as of December 31, 2022, will be deferred for consideration in the Company's 2022 base rate case.

The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2022 base rate case.

Any unusable materials and supplies inventory balance remaining at the date of each unit retirement shall be reclassified as a regulatory asset and the timing of recovery deferred for consideration in the Company's 2022 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2022 base rate case.

38. The remaining units that are decertified and retired pursuant to the final order issued in this IRP are projected to retire after 2025. As such, the Stipulating Parties have agreed for purposes of settling this case that the remaining net book values and unusable materials and supplies inventory balances, if any, for those generating units retiring after 2025 approved in this case will be reclassified to regulatory asset accounts as of the units' retirement dates. The timing of recovery for the regulatory assets, if a balance remains, shall be decided in a future base rate case.

39. Following each unit's dismantlement, any over or under recovered cost of removal balances shall be reviewed in a future base rate case.

40. The capital and O&M costs the Company will incur for the subsequent license review for Plant Hatch Units 1-2 (but not yet the recovery of such costs) are approved as presented in this IRP.

41. The Company agrees to update its Residential Consumer Survey to collect more recent information regarding the end-use market saturation and incorporate as appropriate in the 2025 IRP.

42. The Company agrees to file with the 2025 IRP a forecast scenario of Georgia Power's Peak Demand and Energy forecast using weather normal data for the most recent 20 years.

43. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to PIA Staff in an amount not to exceed $500,000 annually.

This amount paid by Georgia Power under this Paragraph shall be deemed as a necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.

Demand Side Plan

1. The Company's DSM Certification is approved as filed with the following adjustments proposed by PIA Staff and agreed to by the Company.

2. The Company will include an additional sensitivity in its 2025 IRP development and resource optimization process. In this additional sensitivity case, DSM resources, including demand response and energy efficiency, will be allowed to compete head-to-head with supply-side options in the Company's IRP model as a selectable resource. This new sensitivity will replace the Aggressive Case scenario in the DSM Program Planning Process. The Commission will authorize the Company to recover the additional costs required to complete this new sensitivity through the DSM rider after review and approval by Commission Staff. To implement this change:

    a. Step 8 in the DSM Program Planning Process will be revised to state: "The Company will also produce an additional sensitivity in its 2025 IRP development and resource optimization process, where DSM is allowed to compete head-to-head with supply-side options in the Company's IRP model as a selectable resource."

    b. Step 9 in the DSM Program Planning Process will be revised to state: "The Company will use the difference in costs between the base case and the Proposed DSM change case configuration to determine the avoided generation cost impact of the DSM measures in the Proposed DSM change case. As the final step, the cost effectiveness tests mentioned in item 6 (above) will be calculated based on the inputs and adjustments from the system tools. Revenue impacts will be based on current rates and escalations based on the Company's financial projections adjusted for the DSM cost impacts. The avoided generation costs from the system tools and the avoided Transmission and Distribution ("T&D") revenue requirements as estimated by PRICEM will be used to calculate the benefits of the RIM, TRC and Program Administrator test for the Proposed DSM change case. The projected deadline for including new programs in the system planning process is October 1, 2024.

3. The Demand Side Management Working Group ("DSMWG") will continue in its current form and be involved in the development of future DSM programs in the same manner it has operated in past IRP cycles.

4. The Commission will approve the Company's request for decertification of the Residential Power Credit and Commercial Midstream Programs, approval of the certification of the HopeWorks Program, approval of the Company's waiver request for Commission Rule 515-3-4-.04(4)(a)3 for the Thermostat Demand Response Program, and approval of the amended certificates for the Residential Behavioral, Residential Home Energy Improvement Program ("HEIP"), Residential Refrigerator Recycling, Residential Specialty Lighting, Residential Home Energy Efficiency Assistance, Commercial Custom, Commercial Prescriptive, Commercial Small Commercial Direct Install, and Commercial Behavioral Programs.

5. The Company will pause the Commercial Behavioral Program, pending decertification, if the upcoming 2024 Evaluation, Measurement, and Verification ("EM&V") does not show the program to be cost effective.

6. The Residential Investment to Save Energy ("RISE") pilot will continue for the 2023-2025 program cycle in its current form.

7. The Automated Benchmarking Tool ("ABT") will continue for the 2023-2025 program cycle as approved in the 2019 IRP at a preapproved cost of $600,000.

8. The HEIP will be expanded to include the proposed Manufactured Homes Program, with the exception of "whole home replacement" measures, as described in the PIA Staff's testimony.

9. The DSM energy savings targets will be adjusted using the Applied Energy Group ("AEG") tool used by the Company in this case in order to add the savings from the additions in Paragraph 8 to the HEIP.

10. The DSM program budget will include a reduction of non-incentive costs for certified programs by a total of $4 million over the three-year program cycle.

11. The Commercial Custom Program will include a per building cap of $75,000 in its final program plan.

12. The Education Initiative-Learning Power budget will be $4 million annually for 2023-2025.

13. The annual Residential and Commercial Energy Efficiency Consumer Awareness budgets will be $4.5 million and $1.1 million, respectively, for the 2023-2025 program cycle.

14. The DSM pilot budget will be $3 million per year, to be split evenly between Residential and Commercial classes. The Company will seek Staff's input regarding any proposed pilots before they are implemented and throughout the course of the pilot.

15. The current methodology approved for the DSM additional sum mechanism will continue with an increase to 9.5% of shared savings, and the Company's additional sum will continue to be based on net energy savings rather than gross energy savings.

16. Once the Company selects program implementers and program plans are developed, these plans will be provided to PIA Staff for review and input prior to implementation of the corresponding programs. The Company should provide PIA Staff with at least 15 days for review of the Final Program Plans.

17. The current DSM true-up process will continue, including not allowing the rollover of unspent annual budget dollars or unrealized savings targets.

18. The three-year program EM&V cycle will continue from 2023 to 2025.

19. As set forth in Staff's testimony, the 2021 and 2018 EM&V results will be used as recommended by the independent program evaluators.

20. For commercial lighting hours of use ("HOU"), the Company will continue to use the AEG design tool's results for energy savings for the current cycle. The Company agrees to do a commercial lighting HOU study in the 2024 EM&V process and will apply those results as determined by the evaluator for future programs.

21. The Company will evaluate income-qualified savings in a manner consistent with the remainder of the Residential sector to confirm whether this NTG assumption is appropriate. The Company will work with Staff to determine whether values

derived from the EM& V results should be used in future income qualified program planning.

22. Staff recommends the continuation of the current policy to implement the EM&V results in the first year of the next IRP cycle.

23. The upcoming EM&V shall include a new in-situ metering study for the Refrigerator Recycling Program. The costs of the study will be recovered from the DSM rider.

24. The current Commission policy that requires the Company to provide detailed evaluation plans for each of the approved DSM programs within 90 days of the selection of the Program Implementers for each of the certified programs will continue. However, Staff will work with the Company to extend the 90 days on an as-needed basis as it has in prior IRP cycles.

Agreed to this 10th day of June 2022.

Preston Thomas

On Behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On Behalf of Georgia Power Company