

EXHIBIT\_\_(RCS-1)

**Exhibit RCS-1**  
**QUALIFICATIONS OF RALPH C. SMITH**

**Accomplishments**

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

### Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

### Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.



Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA	
&76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA	
& 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001	
& ER-85647001	New England Power Company (FERC)
850782-EI &	
850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU	
& 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
T E-1032-88-102	Illinois Bell Telephone Company (Illinois CC)
89-0033	Puget Sound Power & Light Company (Washington UTC))
U-89-2688-T	Philadelphia Electric Company (Pennsylvania PUC)
R-891364	Potomac Electric Power Company (District of Columbia PSC)
F.C. 889	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
Case No. 88/546	
87-11628	Duquesne Light Company, et al, plaintiffs, against Gulf+Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
& U-1551-89-103	
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and	Intrastate Access Charge Methodology, Pool and Rates
TC-91-040B	Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS &	General Development Utilities - Port Malabar and
911-67-WS	West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314	
& M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 &	
U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 &	Citizens Utilities Company - Gas Division
U-1032-93-193	(Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/	Sale of Assets CC&N from Contel of the West, Inc. to
E-1032-93-169	Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed	Citizens Utility Company - Arizona Telephone Operations
Staff Investigation	(Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania
	(Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-
	Nuclear Generation Assets, & Transition Costs for Electric Utility
	Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and
	San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its
	Restructuring Plan Under Section 2806 of the Public Utility Code
	(Pennsylvania PUC)
97-65	Application of Delmarva Power & Light Co. for Application of a
	Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed	Delaware - Estimate Impact of Universal Services Issues
Staff Investigation	(Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric
	Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision
	of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60,	Investigation of 1998 Intrastate Access charge filings
U-98-65, U-98-67	(Alaska PUC)
(U-99-66, U-99-65,	Investigation of 1999 Intrastate Access Charge filing
U-99-56, U-99-52)	(Alaska PUC)
Phase II of	
97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed	Bell Atlantic - Delaware, Inc., Review of New Telecomm.
Assistance	and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI
	(Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and
	Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC)
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No.	
98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No.	Post-Transition Ratemaking Mechanisms for the Electric Industry
99-01-016,	Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020	Pacific Gas & Electric Company Rate Case (California PUC)
Phase II	United Illuminating Company (Connecticut OCC)
01-10-10	Georgia Power FCR (Georgia PSC)
13711-U	Verizon Delaware § 271(Delaware DPA)
02-001	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-BLVT-377-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	
P404, 407, 520, 413	
426, 427, 430, 421/	
CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No.	
E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No.	
05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No.	
03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363,	
Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM,	
Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)

Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA,	
06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208,	
R-2010-2166210,	
R-2010-2166212, &	
R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)



Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
Cause No. 43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
E-04230A-14-0011 & E-01933A-14-0011	Reorganization of UNS Energy Corporation with Fortis, Inc. (Arizona CC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
Formal Case No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)
Cause No. 43114-IGCC-12/13	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
15-03-45 <sup>^</sup>	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)

2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)
PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
Docket No. 2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38 <sup>^^</sup>	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26 <sup>^^</sup>	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/SR-2015-0302	Missouri American Water Company (Missouri PSC)
U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
P-15-014	PTE Pipeline LLC (Regulatory Commission of Alaska)
P-15-020	Swanson River Oil Pipeline, LLC (Regulatory Commission of Alaska)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P	
(Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)
E-01345A-16-0036	Arizona Public Service Company (Arizona CC)
Docket No. 4618	Providence Water Supply Board (Rhode Island PUC)
Docket No. 46238	Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy Inc. (Texas State Office of Administrative Hearings; Texas PUC)
U-16-066	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Case No. 2016-00370	Kentucky Utilities Company (Kentucky PSC)
Case No. 2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142*	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322*	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034*	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)

Case No. 9449	Merger of AltaGas Ltd. and WGL Holdings (Maryland PSC)
Formal Case No. 1142	Merger of AltaGas Ltd. and WGL Holdings (District of Columbia PSC)
Case No. 2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
Docket No. 2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)
U-18-021 & U-18-033	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 4800	Suez Water Rhode Island Inc. (Rhode Island PUC)
General Order No. 236.1	In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act (West Virginia PSC)
20180047-EI	Duke Energy Florida, LLC. (Florida PSC)
20180046-EI	Florida Power & Light Company (Florida PSC)
20180048-EI	Florida Public Utilities Company – Electric (Florida PSC)
20180052-GU	Florida Public Utilities Company – Indiantown (Florida PSC)
20180054-GU	Florida Division of Chesapeake Utilities Corporation (Florida PSC)
20180051-GU	Florida Public Utilities Company – Gas Division (Florida PSC)
20180053-GU	Florida Public Utilities Company - Fort Meade (Florida PSC)
Cause No. 45032 S4	Indiana American Water Company, Inc. Phase 2 (Indiana Utility Regulatory Commission)
Docket No. D2018.1.6	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. D2018.4.24	NorthWestern Energy (Montana PSC)
Docket No. D2018.4.22	Montana-Dakota Utilities Co. (Montana PSC)
18-0573-W-42T & 18-0576-S-42T	West Virginia-American Water Company (West Virginia PSC)
18-0646-E-42T & 18-0645 E-D	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
18-0049-GA-ALT, 18-0298-GA-AIR, & 18-0299-GA-ALT	Vectren Energy Delivery of Ohio, Inc. (Ohio PUC)
R-2018-3003558, R-2018-3003561	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
Cause No. 45142	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
U-18-043	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
T-03214-17-0305	Citizens Telecommunications Company of The White Mountains, Inc. d/b/a Frontier Communications of The White Mountains (Arizona CC)
Docket No. D2018.9.60	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. 4890	Narragansett Bay Commission (Rhode Island PUC)
PUR-2018-00131	Columbia Gas of Virginia (Virginia SCC)
EL18-152-000	Louisiana PSC v. System Energy Resources, Inc. and Entergy Services, Inc. (FERC)
PUR-2018-00175	Virginia-American Water Company (Virginia SCC)
A-2018-3006061, A-2018-3006062 and A-2018-3006063	Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC (Pennsylvania PUC)
Docket No. 42310	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
U-18-102	Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
PUC Docket No. 49494	AEP Texas, Inc. (Texas PUC)

Application 18-12-009	Pacific Gas and Electric Company (California PUC)
19-0316-G-42T	Mountaineer Gas Company (West Virginia PSC)
19-0051-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
ER-18-1182-001	System Energy Resources, Inc. (FERC)

\* Testimony filed, examination not completed

\*\* Issues stipulated

\*\*\* Company withdrew case

^ Testimony filed, case withdrawn after proposed decision issued

^^ Issues stipulated before testimony was filed

Exhibit\_(RLT-1)

Exhibit\_(RLT-1)

Qualifications of Robert L. Trokey

Mr. Trokey received a Bachelor of Arts degree in Economics from the California State University, Chico in May 1993. In July 1997, he received a Master of Arts degree in Economics from the University of Colorado, Boulder.

From August 1995 to August 1998 Mr. Trokey worked as an Economist and Chief Operating Officer for Systems and Education Development International, Corporation, a Denver-based management consulting firm. His duties included managing operations, accounting, conducting economic research and developing business plans for international clients.

Mr. Trokey worked as an Auditor for Cable Audit Associates in Greenwood Village, Colorado from September 1998 to July 1999. Cable Audit Associates represents various cable programmers by conducting subscriber audits, providing accounting services and contract compliance testing.

From August 1999 to December 2000 he was employed by KeyBank National Association as a Portfolio Monitoring Analyst, becoming the lead analyst for the Colorado Upper Middle Market portfolio. Responsibilities included monitoring performance of commercial loans exceeding \$25 million, collecting and analyzing financial statements and SEC reports, projecting and forecasting financial trends, establishing risk ratings, reviewing asset-based lending documents, calculating financial ratios and testing loan covenants.

Mr. Trokey began working for the Colorado Office of Consumer Counsel in January 2001 as a General Professional III, Office Manager. As of August 2004, his position was reclassified as a Budget Analyst II. In March 2006 he was promoted to the Rate/Financial Analyst III position.

Comments and Testimony filed on behalf of the Colorado Office of Consumer Counsel:

DOCKET NO. 06I-084T: IN THE MATTER OF AN INVESTIGATION OF REVISING THE DEFINITION OF BASIC LOCAL EXCHANGE TELEPHONE SERVICE OR BASIC SERVICE.

- Initial Comments of the Colorado Office of Consumer Counsel, April 10, 2006

DOCKET NO. 06S-234EG: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO FOR ADVICE LETTER NO. 1454 – ELECTRIC AND ADVICE LETTER NO. 671 – GAS.

- Answer Testimony and Exhibits of Robert L. Trokey, August 18, 2006

DOCKET NO. 06S-656G: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO FOR ADVICE LETTER NO. 690 – GAS.

- Answer Testimony and Exhibits of Robert L. Trokey, April 6, 2007

In September of 2007, Mr. Trokey joined the Georgia Public Service Commission as a Utilities Analyst. In this capacity, he has participated in Integrated Resource Planning, Rate Cases, Annual Surveillance Reports (lead analyst), construction monitoring, environmental compliance, demand-side management working groups, and fuel cost recovery dockets as well as other matters.

Testimony filed on behalf of the Georgia Public Service Commission, Public Interest Advocacy Staff:

DOCKET NO. 40161: IN THE MATTER OF GEORGIA POWER COMPANY’S 2016 INTEGRATED RESOURCE PLAN AND APPLICATION FOR DECERTIFICATION OF PLANT MITCHELL UNITS 3, 4A AND 4B, PLANT KRAFT UNIT 1 CT, AND INTERCESSION CITY CT

- Direct testimony and exhibits of Ralph C. Smith and Robert L. Trokey, May 6, 2016

Docket No. 42310: IN THE OF GEORGIA POWER COMPANY’S 2019 INTEGRATED RESOURCE PLAN AND APPLICATION FOR CERTIFICATION OF CAPACITY FROM PLANT SCHERER UNIT 3 AND PLANT GOAT ROCK UNITS 9-12 AND APPLICATION FOR DECERTIFICATION OF PLANT HAMMOND UNITS 1-4, PLANT MCINTOSH UNIT 1, PLANT LANGDALE UNITS 5-6, PLANT RIVERVIEW UNITS 1-2, AND PLANT ESTATOAH UNIT 1

- Direct testimony and exhibits of Ralph C. Smith and Robert L. Trokey, April 25, 2019

EXHIBIT\_\_(RS/RT-2)



Georgia Power Company  
Docket No. 42516  
Staff Exhibit \_\_\_\_(RS/RT-2)

Staff Revenue Requirement and Adjustment Schedules  
**Accompanying the Direct Testimony of Ralph C. Smith and Robert Trokey**

Schedule	Description	Primary Staff Witnesses	Confidential	No. of Pages	Page No.
<b>Revenue Requirement Summary Schedules</b>					
A	Computation of Increase in Gross Revenue Requirement	R. Smith/R. Trokey	No	1	2
A-1	Computation of Gross Revenue Conversion Factor	R. Smith/R. Trokey	No	2	3-4
A-2	Revenue Requirement Reconciliation	R. Smith/R. Trokey	No	4	5-8
B	Adjusted Rate Base	R. Smith/R. Trokey	No	4	9-12
B.1	Summary of Rate Base Adjustments	R. Smith/R. Trokey	No	1	13
B.1 (2020)	Summary of Rate Base Adjustments Calendar 2020	R. Smith/R. Trokey	No	1	14
B.1 (2021)	Summary of Rate Base Adjustments Calendar 2021	R. Smith/R. Trokey	No	1	15
B.1 (2022)	Summary of Rate Base Adjustments Calendar 2022	R. Smith/R. Trokey	No	1	16
C	Adjusted Net Operating Income	R. Smith/R. Trokey	No	4	17-20
C.1	Summary of Net Operating Income Adjustments Test Year Ending July 31, 2020	R. Smith/R. Trokey	No	1	21
C.1 (2020)	Summary of Net Operating Income Adjustments Calendar 2020	R. Smith/R. Trokey	No	1	22
C.1 (2021)	Summary of Net Operating Income Adjustments Calendar 2021	R. Smith/R. Trokey	No	1	23
C.1 (2022)	Summary of Net Operating Income Adjustments Calendar 2022	R. Smith/R. Trokey	No	1	24
D	Capital Structure & Cost Rates	T. Newsome/ M. Gorman	No	4	25-28
<b>Adjustment Schedules</b>					
E-1	Company Errata - Rate Base Adjustments	R. Smith/R. Trokey	No	5	29-33
E-2	Company Errata - Operating Income Adjustments	R. Smith/R. Trokey	No	4	34-37
E-3	Interest Credits on Minimum Bank Balances	R. Smith/R. Trokey	No	1	38
E-4	EV Charging Facilities	R. Smith/R. Trokey	No	1	39
E-5	Cash Working Capital	R. Smith/R. Trokey	No	4	40-43
E-6	Executive Financial Planning	R. Smith/R. Trokey	No	1	44
E-7	Property Tax Expense	R. Smith/R. Trokey	No	1	45
E-8	Interest Synchronization Adjustment	R. Smith/R. Trokey	No	4	46-49
E-9	Stock-Based Compensation	R. Smith/R. Trokey	No	4	50-53
E-10	Payroll Tax Expense	R. Smith/R. Trokey	No	1	54
E-11	Uncollectibles Expense	R. Smith/R. Trokey	No	1	55
E-12	Storm Damage Accrual	R. Smith/R. Trokey	No	4	56-59
<b>Other Schedules</b>					
F-1	Depreciation Expense and Accumulated Depreciation - Depreciation Rates	R. Smith/R. Trokey	No	17	60-76
F-2	Accumulated Deferred Income Taxes - Impact of Depreciation Rates	R. Smith/R. Trokey	No	1	77
Total Pages, Including Content Listing				77	

Line No.	Description	Reference	Company Proposed Traditional Rate Case (A)	Three-Year Plan, 2020-2022 (B)	Traditional Rate Case (C)	Staff Calculated 2020 (D)	2021 (E)	2022 (F)	Difference Traditional Rate Case (G)=C-A
1	Adjusted Rate Base	Sch. B	\$ 20,097,349	\$ 20,097,349	\$ 20,063,489	\$ 20,662,417	\$ 21,672,609	\$ 22,628,881	\$ (33,860)
2	Rate of Return	Sch. D	7.93%	7.93%	6.69%	6.73%	6.75%	6.75%	
3	Operating Income Required for Rate of Return		\$ 1,594,261	\$ 1,594,261	\$ 1,341,505	\$ 1,389,651	\$ 1,463,963	\$ 1,526,341	\$ (252,756)
4	Net Operating Income Available	Sch. C	\$ 1,448,591	\$ 1,448,591	\$ 1,476,618	\$ 1,415,813	\$ 1,252,479	\$ 1,043,804	\$ 28,028
5	Operating Income Excess/Deficiency		\$ 145,670	\$ 145,670	\$ (135,113)	\$ (26,162)	\$ 211,484	\$ 482,537	\$ (280,784)
6	Gross Revenue Conversion Factor	Sch. A-1	1.3404	1.3404	1.3402	1.3402	1.3402	1.3402	
7	Base Rate Revenue Deficiency		\$ 195,263	\$ 195,263	\$ (181,078)	\$ (35,063)	\$ 283,428	\$ 646,685	\$ (376,342)
8	ECCR Revenue Deficiency	Ex. RSRT-3 -	\$ 173,625	\$ 173,625 [a]	\$ 112,688	\$ 121,090	\$ 106,974	\$ 82,683	\$ (60,936)
9	DSM Revenue Deficiency	Ex. RSRT-4 -	\$ 14,330	\$ 14,330	\$ 11,869	\$ 11,915	\$ 13,171	\$ 13,988	\$ (2,461)
10	Traditional Base Rate Revenue Deficiency		\$ 7,309	\$ 7,309	\$ (305,635)	\$ (168,067)	\$ 163,284	\$ 550,013	\$ (312,944)
11	CCR ARO Compliance Revenue Deficiency Applicable to Traditional Base Rate Tariffs	Ex. RSRT-6 -	\$ 151,292	\$ 151,292	\$ 102,566	\$ 104,606	\$ 202,837	\$ 362,001	\$ (48,726)
12	Revenue Deficiency Applicable to Traditional Base Rate Tariffs Less CCR ARO Compliance		\$ (143,983)	\$ (143,983)	\$ (408,202)	\$ (272,673)	\$ (39,554)	\$ 188,012	\$ (264,218)
13	Levelized Revenue Deficiency Adjustment		\$ 353,207	\$ 353,207					\$ (353,207)
14	Revenue Deficiency Applicable to Traditional Base Rate Tariffs Less CCR ARO Compliance		\$ 209,224	\$ 209,224	\$ (408,202)	\$ (272,673)	\$ (39,554)	\$ 188,012	\$ (617,426)
15	Revenue Deficiency Applicable to Traditional Base Rate Tariffs for CCR ARO Compliance		\$ 158,110	\$ 158,110	\$ 104,606	\$ 104,606	\$ 202,837	\$ 362,001	\$ (53,504)
16	Total Base Rate Revenue Deficiency		\$ 367,334	\$ 367,334	\$ (303,596)	\$ (168,067)	\$ 163,284	\$ 550,013	\$ (670,929)
17	Change from 2020 to 2021 and from 2021 to 2022						\$ 331,351	\$ 386,729	

Notes and Source

Col. A&B: Company Exhibit (DPP/SPA/MBR-1, Schedule 1 of 10 and Exhibit (DPP/SPA/MBR-1, Schedule 2 Traditional Base)

[a]: Per Company Exhibit (DPP/SPA/MBR-1, Schedule 3), page 2 of 5, the Company has proposed to levelize the ECCR revenue requirement from \$173.6 million to \$164.9 million by making a levelized adjustment to reduce the \$173.6 million by \$8.7 million

Line 15: The 2020 amount for the CCR-ARO compliance revenue deficiency is also used for the test year in the Company and Staff presentation to reflect that collection would start on January 1, 2020. For the 2021 and 2022 amounts, Staff recommends that the Company file a compliance filing by October 1, 2020 and 2021, respectively, for the 2021 and 2022 step increases.

Georgia Power Company  
Computation of Gross Revenue Conversion Factor

Exhibit \_\_ (RS/RT-2)  
Schedule A-1  
Page 1 of 2

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Income Taxes (A)	Company Proposed (B)	Staff Proposed (C)
1	Gross Revenue		100.000%	100.00%
2	Less: Federal and State Income Taxes	25.296%	25.296%	25.296%
3	Net Revenue After Income Taxes		74.704%	74.704%
	<b>Less: Uncollectibles</b>			
4	Estimated Uncollectibles		\$ 13,445	\$ 12,000
5	Retail Revenue (Excluding Street & Hwy Lighting)		\$ 7,691,172	\$ 7,691,172
6	Uncollectible Accounts (Before Income Taxes)		0.175%	0.156%
7	Less: Federal and State Income Taxes	25.296%	0.044%	0.039%
8	Net Effect of Uncollectible Accounts		0.131%	0.117%
	<b>Add: Additional Compensation for Collecting State Sales Taxes</b>			
9	Estimated Sales Tax Percentage		7.519%	7.52%
10	Collection Fee Received		0.500%	0.50%
11	Additional Compensation (Before Income Taxes)		0.038%	0.038%
12	Less: Federal and State Income Taxes	25.296%	0.010%	0.010%
13	Net Effect of Uncollectible Accounts		0.028%	0.028%
14	After Tax Effect of Additional Revenue (Income Expansion Factor)		74.602%	74.616%
15	Gross Revenue Conversion Factor		1.340447	1.340195

Notes and Source

Col.B: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 2 of 10

Col.C: Staff proposed.

\* Staff is recommending uncollectibles expense of \$12 million for each plan year - See Schedule E-11

Georgia Power Company  
Computation of Gross Revenue Conversion Factor

Exhibit \_\_ (RS/RT-2)  
Schedule A-1  
Page 2 of 2

(Thousands of Dollars)

Line No.	Description	Income Taxes (A)	Calendar 2020		Calendar 2021		Calendar 2022	
			Company Proposed (B)	Staff Proposed (C)	Company Proposed (D)	Staff Proposed (E)	Company Proposed (F)	Staff Proposed (G)
1	Gross Revenue		100.000%	100.000%	100.000%	100.000%	100.000%	100.000%
2	Less: Federal and State Income Taxes	25.296%	25.296%	25.296%	25.296%	25.296%	25.296%	25.296%
3	Net Revenue After Income Taxes		74.704%	74.704%	74.704%	74.704%	74.704%	74.704%
<b>Less: Uncollectibles</b>								
4	Estimated Uncollectibles		\$ 14,003	\$ 12,000 *	\$ 14,003	\$ 12,000 *	\$ 14,004	\$ 12,000
5	Retail Revenue (Excluding Street & Hwy Lighting)		\$ 7,649,528	\$ 7,649,528	\$ 7,709,482	\$ 7,709,482	\$ 7,758,733	\$ 7,758,733
6	Uncollectible Accounts (Before Income Taxes)		0.183%	0.157%	0.182%	0.156%	0.180%	0.155%
7	Less: Federal and State Income Taxes	25.296%	0.046%	0.040%	0.046%	0.039%	0.046%	0.039%
8	Net Effect of Uncollectible Accounts		0.137%	0.117%	0.136%	0.116%	0.135%	0.116%
<b>Add: Additional Compensation for Collecting State Sales Taxes</b>								
9	Estimated Sales Tax Percentage		7.519%	7.519%	7.519%	7.519%	7.519%	7.519%
10	Collection Fee Received		0.500%	0.500%	0.500%	0.500%	0.500%	0.500%
11	Additional Compensation (Before Income Taxes)		0.038%	0.038%	0.038%	0.038%	0.038%	0.038%
12	Less: Federal and State Income Taxes	25.296%	0.010%	0.010%	0.010%	0.010%	0.010%	0.010%
13	Net Effect of Uncollectible Accounts		0.028%	0.028%	0.028%	0.028%	0.028%	0.028%
14	After Tax Effect of Additional Revenue (Income Expansion Factor)		74.596%	74.615%	74.597%	74.616%	74.598%	74.617%
15	Gross Revenue Conversion Factor		1.340558	1.340206	1.340539	1.340190	1.340523	1.340177

Notes and Source

Cols. B, D & F: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 2 of 10

Cols. C, E and G: Staff proposed

\* Staff is recommending uncollectibles expense of \$12 million for each plan year - See Schedule E-11

Notes and Source	Pre-tax return computed using Gross Revenue Conversion Factor
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### Effect of Staff Adjustments to Rate Base

#### Staff Rate Base Multiplier

Line No.	Description	Schedule Reference	Component (A)	Net Operating Income Amount Sch C.1 (B)	Rate Base Adjustment Sch B.1 (C)	Staff Rate Base Multiplier (D)	Staff Multiplier (E)	Staff Estimated Revenue Requirement Impact (F)
1		D	ROR Difference					
2	<b>Rate Base</b>	A-1	GRCF					
3	Rate Base per Company's Filing	B		x	\$ 20,712.373	x	-1.2561% 1.340206 -1.683%	\$ (348,685)
<b>Estimated Revenue Requirement Effect of Staff NOI and Rate Base Adjustments</b>								
4	Company Errata - Rate Base Adjustments	Staff Adjustment	Pre-Tax Operating Income Amount				Staff GRCF NOI Multiplier	
5	Company Errata - Operating Income Adjustments	E-1	\$ -	\$ -	\$ (34,914)	9.01%	1.340206	\$ (3,147)
6	Interest Credits on Minimum Bank Balances	E-2	\$ 2,063	\$ (5,973)	\$ -	9.01%	1.340206	\$ 8,005
7	EV Charging Facilities	E-3	\$ (272)	\$ 203	\$ -	9.01%	1.340206	\$ (272)
8	Cash Working Capital	E-4	\$ (463)	\$ 261	\$ (3,902)	9.01%	1.340206	\$ (702)
9	Executive Financial Planning	E-5	\$ -	\$ -	\$ (3,100)	9.01%	1.340206	\$ (279)
10	Property Tax Expense	E-6	\$ (409)	\$ 306	\$ -	9.01%	1.340206	\$ (410)
11	Interest Synchronization Adjustment	E-7	\$ (2,575)	\$ 1,924	\$ -	9.01%	1.340206	\$ (2,579)
12	Stock-Based Compensation	E-8	\$ -	\$ 8,002	\$ -	9.01%	1.340206	\$ (10,724)
13	Payroll Tax Expense	E-9	\$ (19,402)	\$ 14,494	\$ -	9.01%	1.340206	\$ (19,425)
14	Uncollectibles Expense	E-10	\$ (1,484)	\$ 1,109	\$ -	9.01%	1.340206	\$ (1,486)
15	Storm Damage Accrual	E-11	\$ (1,978)	\$ 1,478	\$ -	9.01%	1.340206	\$ (1,981)
16		E-12	\$ (4,305)	\$ 3,216	\$ (8,040)	9.01%	1.340206	\$ (5,034)
17	Other Schedules							
18	Depreciation Expense and Accumulated Depreciation - Depreciation Rates	F-1						
19	Accumulated Deferred Income Taxes - Impact of Depreciation Rates	F-2						
20	Sum of Staff's Adjustments		\$ (28,824)	\$ 25,020	\$ (49,956)			
21	Company Proposed Net Operating Income and Rate Base			\$ 1,390,793	\$ 20,712.373			
22	<b>Staff Adjusted Net Operating Income and Staff Adjusted Rate Base</b>	C		\$ 1,415,813	\$ 20,662,417			
<b>Gross Revenue Conversion Factor Difference:</b>								
23	Per Staff	A-1					1.340206	
24	Per Company	A-1					1.340558	
25	Difference						-0.000352	
26	Company Adjusted NOI Deficiency	A			\$ 262,390			\$ (92)
27	GRCF Difference							\$ (386,812)
28	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE							\$ 351,749
29	Company Requested Base Rate Revenues, Not Including Levelization	A						\$ (35,063)
30	Reconciled Revenue Requirement							\$ (35,063)
31	Revenue Requirement Calculated on Schedule A	A						\$ (0)
32	Unidentified Difference (rounding)							

Notes and Source  
Pre-tax return computed using Gross Revenue Conversion Factor

<b>Effect of Staff Adjustments to Rate Base</b>					
Staff Rate Base Multiplier	D	Rate of Return	6.73%		
	A-1	GRCF	x	1.340206	
				9.01%	

Line No.	Description	Schedule Reference	Component (A)	Net Operating Income Amount Sch C.1 (B)	Rate Base Adjustment Sch B.1 (C)	Staff Rate Base Multiplier (D)	Staff Multiplier (E)	Staff Estimated Revenue Requirement Impact (F)
1		D	ROR Difference					
2	<b>Rate Base</b>	A-1	GRCF					
3	Rate Base per Company's Filing	B		x	\$ 21,797,091	x	-1.3186% 1,340,190	\$ (385,197)
							-1.767% 1,340,190	\$ (385,197)
<b>Estimated Revenue Requirement Effect of Staff NOI and Rate Base Adjustments</b>								
4	Company Errata - Rate Base Adjustments	Staff Adjustment	Pre-Tax Operating Income Amount				Staff GRCF NOI Multiplier	
5	Company Errata - Operating Income Adjustments	E-1	\$ -	\$ -	\$ (112,455)	9.05%	1,340,190	\$ (10,180)
6	Interest Credits on Minimum Bank Balances	E-2	\$ (1,477)	\$ (6,016)	\$ -	9.05%	1,340,190	\$ 8,063
7	EV Charging Facilities	E-3	\$ (272)	\$ 203	\$ -	9.05%	1,340,190	\$ (272)
8	Cash Working Capital	E-4	\$ (525)	\$ 304	\$ (5,503)	9.05%	1,340,190	\$ (906)
9	Executive Financial Planning	E-5	\$ -	\$ -	\$ (1,700)	9.05%	1,340,190	\$ (154)
10	Property Tax Expense	E-6	\$ (409)	\$ 306	\$ -	9.05%	1,340,190	\$ (410)
11	Interest Synchronization Adjustment	E-7	\$ (2,575)	\$ 1,924	\$ -	9.05%	1,340,190	\$ (2,579)
12	Stock-Based Compensation	E-8	\$ -	\$ 4,658	\$ -	9.05%	1,340,190	\$ (6,243)
13	Payroll Tax Expense	E-9	\$ (21,283)	\$ 15,899	\$ -	9.05%	1,340,190	\$ (21,308)
14	Uncollectibles Expense	E-10	\$ (1,629)	\$ 1,217	\$ -	9.05%	1,340,190	\$ (1,631)
15	Storm Damage Accrual	E-11	\$ (1,978)	\$ 1,478	\$ -	9.05%	1,340,190	\$ (1,981)
16		E-12	\$ (4,305)	\$ 3,216	\$ (4,824)	9.05%	1,340,190	\$ (4,746)
17	Other Schedules							
18	Depreciation Expense and Accumulated Depreciation - Depreciation Rates	F-1						
19	Accumulated Deferred Income Taxes - Impact of Depreciation Rates	F-2						
20	Sum of Staff's Adjustments		\$ (34,453)	\$ 23,188	\$ (124,482)			
21	Company Proposed Net Operating Income and Rate Base			\$ 1,229,291	\$ 21,797,091			
22	<b>Staff Adjusted Net Operating Income and Staff Adjusted Rate Base</b>	C		\$ 1,252,479	\$ 21,672,609			
<b>Gross Revenue Conversion Factor Difference:</b>								
23	Per Staff	A-1					1,340,190	
24	Per Company	A-1					1,340,539	
25	Difference						-0.000349	
26	Company Adjusted NOI Deficiency	A					\$ 530,500	
27	GRCF Difference							\$ (185)
28	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE							\$ (427,728)
29	Company Requested Base Rate Revenues, Not Including Levelization	A						\$ 711,156
30	Reconciled Revenue Requirement							\$ 283,428
31	Revenue Requirement Calculated on Schedule A	A						\$ 283,428
32	Unidentified Difference (rounding)							\$ (0)

Notes and Source  
Pre-tax return computed using Gross Revenue Conversion Factor

**Effect of Staff Adjustments to Rate Base**  
Staff Rate Base Multiplier

D	Rate of Return	6.75%
A-1	GRCF	1,340,190
		x
		9.05%

Line No.	Description	Schedule Reference	Component (A)	Net Operating Income Amount Sch.C.1 (B)	Rate Base Adjustment Sch.B.1 (C)	Staff Rate Base Multiplier (D)	Staff Multiplier (E)	Staff Estimated Revenue Requirement Impact (F)
1		D						
2	<b>Rate Base</b>	A-1	ROR Difference				-1.3851%	
3	Rate Base per Company's Filing	B	GRCF		x \$ 22,848,345	x	<u>1.340177</u>	
							<u>-1.856%</u>	\$ (424,125)
<b>Estimated Revenue Requirement Effect of Staff NOI and Rate Base Adjustments</b>								
4	Company Errata - Rate Base Adjustments							
5	Company Errata - Operating Income Adjustments	Staff Adjustment	Pre-Tax Operating Income Amount	\$ -	\$ (211,362)	9.04%	Staff GRCF NOI Multiplier Sch. A-1	\$ (19,106)
6	Interest Credits on Minimum Bank Balances	E-1	\$ 131	\$ (6,537)	\$ -	9.04%	1.340177	\$ 8,761
7	EV Charging Facilities	E-2	\$ (272)	\$ 203	\$ -	9.04%	1.340177	\$ (272)
8	Cash Working Capital	E-3	\$ (587)	\$ 348	\$ (6,993)	9.04%	1.340177	\$ (1,099)
9	Executive Financial Planning	E-4	\$ -	\$ -	\$ 500	9.04%	1.340177	\$ 45
10	Property Tax Expense	E-5	\$ (409)	\$ 306	\$ -	9.04%	1.340177	\$ (410)
11	Interest Synchronization Adjustment	E-6	\$ (2,575)	\$ 1,924	\$ -	9.04%	1.340177	\$ (2,578)
12	Stock-Based Compensation	E-7	\$ -	\$ 592	\$ -	9.04%	1.340177	\$ (793)
13	Payroll Tax Expense	E-8	\$ (22,644)	\$ 16,916	\$ -	9.04%	1.340177	\$ (22,670)
14	Uncollectibles Expense	E-9	\$ (1,732)	\$ 1,294	\$ -	9.04%	1.340177	\$ (1,734)
15	Storm Damage Accrual	E-10	\$ (1,979)	\$ 1,478	\$ -	9.04%	1.340177	\$ (1,981)
16	Other Schedules	E-11	\$ (4,305)	\$ 3,216	\$ (1,608)	9.04%	1.340177	\$ (4,455)
17	Depreciation Expense and Accumulated Depreciation - Depreciation Rates	E-12	\$			9.04%	1.340177	\$ -
18	Accumulated Deferred Income Taxes - Impact of Depreciation Rates	F-1				9.04%	1.340177	\$ -
19	Sum of Staff's Adjustments	F-2				9.04%	1.340177	\$ -
20	Company Proposed Net Operating Income and Rate Base							
21	<b>Staff Adjusted Net Operating Income and Staff Adjusted Rate Base</b>							
22		C	\$ (34,371)	\$ 19,739	\$ (219,464)			
				\$ 1,024,065	\$ 22,848,345			
				\$ 1,043,804	\$ 22,628,881			
<b>Gross Revenue Conversion Factor Difference:</b>								
23	Per Staff	A-1					1.340177	
24	Per Company	A-1					<u>1.340523</u>	
25	Difference						<u>-0.000347</u>	
26	Company Adjusted NOI Deficiency	A					\$ 833,549	\$ (289)
27	GRCF Difference							
28	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE							
29	Company Requested Base Rate Revenues, Not Including Levelization	A						\$ (470,707)
30	Reconciled Revenue Requirement							\$ 1,117,391
31	Revenue Requirement Calculated on Schedule A							\$ 646,684
32	Unidentified Difference (rounding)	A						\$ 646,685
								\$ (1)

Notes and Source	Pre-tax return computed using Gross Revenue Conversion Factor
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### Effect of Staff Adjustments to Rate Base Staff Rate Base Multiplier



Georgia Power Company  
Adjusted Rate Base  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule B  
Page 1 of 4

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Original Cost		
		As Adjusted	Staff	As Adjusted
		by Company	Adjustments	by Staff
		(A)	(B)	(C)
	<b>Plant-in-Service</b>			
1	Steam	\$ 9,594,779	\$ (25,098)	\$ 9,569,680
2	Nuclear	\$ 5,040,284	\$ -	\$ 5,040,284
3	Hydro	\$ 813,064	\$ (6,139)	\$ 806,925
4	Other CTs	\$ 3,291,379	\$ -	\$ 3,291,379
5	Total Production	\$ 18,739,507	\$ (31,237)	\$ 18,708,270
6	Transmission	\$ 6,288,972	\$ (417)	\$ 6,288,555
7	Distribution	\$ 10,528,598	\$ -	\$ 10,528,598
8	General	\$ 1,616,363	\$ (4,316)	\$ 1,612,047
9	Intangible	\$ 582,621	\$ (47)	\$ 582,574
10	Total Gross Plant	\$ 37,756,061	\$ (36,017)	\$ 37,720,044
11	Nuclear Fuel	\$ 752,195	\$ -	\$ 752,195
12	Electric Plant Held for Future Use	\$ 116,714	\$ -	\$ 116,714
13	Total Electric Plant	\$ 38,624,971	\$ (36,017)	\$ 38,588,954
	<b>Accumulated Depreciation</b>			
14	Production	\$ (6,162,956)	\$ 10,023	\$ (6,152,933)
15	Transmission	\$ (1,292,791)	\$ 181	\$ (1,292,610)
16	Distribution	\$ (3,264,298)	\$ -	\$ (3,264,298)
17	General	\$ (805,328)	\$ 637	\$ (804,691)
18	Intangible	\$ (419,619)	\$ -	\$ (419,619)
19	Subtotal Accumulated Depreciation	\$ (11,944,993)	\$ 10,841	\$ (11,934,152)
20	Nuclear Fuel Amortization	\$ (390,219)	\$ -	\$ (390,219)
21	Total Accumulated Depreciation	\$ (12,335,211)	\$ 10,841	\$ (12,324,370)
	<b>Accumulated Deferred Income Taxes</b>			
22	Account 190	\$ 646,159	\$ 3,071	\$ 649,230
23	Account 281	\$ (819,142)	\$ -	\$ (819,142)
24	Account 282	\$ (5,061,956)	\$ 4,570	\$ (5,057,386)
25	Account 283	\$ (651,076)	\$ -	\$ (651,076)
26	Accumulated Deferred Income Taxes	\$ (5,886,015)	\$ 7,641	\$ (5,878,375)
	<b>Other Rate Base Items</b>			
27	Fuel and Materials and Supplies	\$ 703,070	\$ (517)	\$ 702,553
28	Payables Associated with Capital M&S	\$ (1,505)	\$ -	\$ (1,505)
29	Minimum Bank Balances, Prepaids	\$ 83,713	\$ (521)	\$ 83,192
30	Prepaid Pension Asset	\$ 1,320,397	\$ -	\$ 1,320,397
31	Customer Deposits	\$ (283,112)	\$ -	\$ (283,112)
32	Accumulated Interest on Customer Deposits	\$ (33,172)	\$ -	\$ (33,172)
33	Operating Reserves	\$ (152,735)	\$ (11,725)	\$ (164,460)
34	Environmental CWIP	\$ 21,198	\$ -	\$ 21,198
35	Retired Units NBV	\$ 588,529	\$ -	\$ 588,529
36	Tax Reform Regulatory Liability	\$ (547,254)	\$ -	\$ (547,254)
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 12,414	\$ -	\$ 12,414
38	Unusable Inventory Regulatory Asset	\$ 37,092	\$ -	\$ 37,092
39	Future Nuclear Regulatory Asset	\$ 40,655	\$ -	\$ 40,655
40	Deferred Nuclear Outage Cost	\$ 39,217	\$ -	\$ 39,217
41	ARO Regulatory Asset (182)	\$ 3,579,099	\$ -	\$ 3,579,099
42	ARO Liability (230)	\$ (5,859,756)	\$ -	\$ (5,859,756)
43	ARO Regulatory Liability (254)	\$ 168,235	\$ 38	\$ 168,274
44	Cash Working Capital	\$ (22,482)	\$ (3,600)	\$ (26,082)
45	Total Other Rate Base Items	\$ (306,395)	\$ (16,325)	\$ (322,720)
46	Total Rate Base	\$ 20,097,349	\$ (33,860)	\$ 20,063,489

Notes and Source

Col.A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 3 of 10

Georgia Power Company  
Adjusted Rate Base  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule B  
Page 2 of 4

Calendar Year 2020  
(Thousands of Dollars)

Line No.	Description	Original Cost		
		As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	<b>Plant-in-Service</b>			
1	Steam	\$ 9,716,382	\$ (42,482)	\$ 9,673,901
2	Nuclear	\$ 5,061,671	\$ -	\$ 5,061,671
3	Hydro	\$ 827,625	\$ (15,195)	\$ 812,430
4	Other CTs	\$ 3,389,271	\$ -	\$ 3,389,271
5	Total Production	\$ 18,994,949	\$ (57,677)	\$ 18,937,272
6	Transmission	\$ 6,454,904	\$ (715)	\$ 6,454,189
7	Distribution	\$ 10,792,519	\$ -	\$ 10,792,519
8	General	\$ 1,720,398	\$ (5,318)	\$ 1,715,080
9	Intangible	\$ 598,308	\$ (80)	\$ 598,228
10	Total Gross Plant	\$ 38,561,078	\$ (63,790)	\$ 38,497,289
11	Nuclear Fuel	\$ 764,660	\$ -	\$ 764,660
12	Electric Plant Held for Future Use	\$ 116,714	\$ -	\$ 116,714
13	Total Electric Plant	\$ 39,442,452	\$ (63,790)	\$ 39,378,663
	<b>Accumulated Depreciation</b>			
14	Production	\$ (6,315,479)	\$ 17,168	\$ (6,298,311)
15	Transmission	\$ (1,304,088)	\$ 312	\$ (1,303,776)
16	Distribution	\$ (3,322,520)	\$ -	\$ (3,322,520)
17	General	\$ (839,756)	\$ 970	\$ (838,786)
18	Intangible	\$ (440,212)	\$ -	\$ (440,212)
19	Subtotal Accumulated Depreciation	\$ (12,222,056)	\$ 18,450	\$ (12,203,605)
20	Nuclear Fuel Amortization	\$ (392,145)	\$ -	\$ (392,145)
21	Total Accumulated Depreciation	\$ (12,614,200)	\$ 18,450	\$ (12,595,750)
	<b>Accumulated Deferred Income Taxes</b>			
22	Account 190	\$ 639,996	\$ 2,722	\$ 642,718
23	Account 281	\$ (803,149)	\$ -	\$ (803,149)
24	Account 282	\$ (5,121,141)	\$ 7,559	\$ (5,113,582)
25	Account 283	\$ (651,569)	\$ -	\$ (651,569)
26	Accumulated Deferred Income Taxes	\$ (5,935,863)	\$ 10,281	\$ (5,925,582)
	<b>Other Rate Base Items</b>			
27	Fuel and Materials and Supplies	\$ 714,148	\$ (839)	\$ 713,309
28	Payables Associated with Capital M&S	\$ (1,529)	\$ -	\$ (1,529)
29	Minimum Bank Balances, Prepaids	\$ 83,191	\$ (904)	\$ 82,287
30	Prepaid Pension Asset	\$ 1,331,914	\$ -	\$ 1,331,914
31	Customer Deposits	\$ (285,645)	\$ -	\$ (285,645)
32	Accumulated Interest on Customer Deposits	\$ (33,418)	\$ -	\$ (33,418)
33	Operating Reserves	\$ (132,649)	\$ (10,049)	\$ (142,698)
34	Environmental CWIP	\$ 18,169	\$ -	\$ 18,169
35	Retired Units NBV	\$ 568,229	\$ -	\$ 568,229
36	Tax Reform Regulatory Liability	\$ (553,908)	\$ -	\$ (553,908)
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 10,641	\$ -	\$ 10,641
38	Unusable Inventory Regulatory Asset	\$ 37,092	\$ -	\$ 37,092
39	Future Nuclear Regulatory Asset	\$ 40,655	\$ -	\$ 40,655
40	Deferred Nuclear Outage Cost	\$ 42,323	\$ -	\$ 42,323
41	ARO Regulatory Asset (182)	\$ 3,602,132	\$ -	\$ 3,602,132
42	ARO Liability (230)	\$ (5,852,196)	\$ -	\$ (5,852,196)
43	ARO Regulatory Liability (254)	\$ 256,869	\$ (6)	\$ 256,863
44	Cash Working Capital	\$ (26,035)	\$ (3,100)	\$ (29,135)
45	Total Other Rate Base Items	\$ (180,016)	\$ (14,898)	\$ (194,913)
46	Total Rate Base	\$ 20,712,373	\$ (49,956)	\$ 20,662,417

Notes and Source

Col.A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 5 of 10

Georgia Power Company  
Adjusted Rate Base  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule B  
Page 3 of 4

Calendar Year 2021  
(Thousands of Dollars)

Line No.	Description	Original Cost		
		As Adjusted	Staff	As Adjusted
		by Company	Adjustments	by Staff
		(A)	(B)	(C)
Plant-in-Service				
1	Steam	\$ 9,816,569	\$ (55,096)	\$ 9,761,473
2	Nuclear	\$ 5,128,331	\$ -	\$ 5,128,331
3	Hydro	\$ 918,627	\$ (84,658)	\$ 833,969
4	Other CTs	\$ 3,698,049	\$ 1,386	\$ 3,699,435
5	Total Production	\$ 19,561,577	\$ (138,368)	\$ 19,423,209
6	Transmission	\$ 6,757,859	\$ (774)	\$ 6,757,084
7	Distribution	\$ 11,554,213	\$ -	\$ 11,554,213
8	General	\$ 1,916,647	\$ (7,378)	\$ 1,909,269
9	Intangible	\$ 666,912	\$ (87)	\$ 666,825
10	Total Gross Plant	\$ 40,457,208	\$ (146,607)	\$ 40,310,601
11	Nuclear Fuel	\$ 734,270	\$ -	\$ 734,270
12	Electric Plant Held for Future Use	\$ 116,714	\$ -	\$ 116,714
13	Total Electric Plant	\$ 41,308,193	\$ (146,607)	\$ 41,161,586
Accumulated Depreciation				
14	Production	\$ (6,861,174)	\$ 19,440	\$ (6,841,734)
15	Transmission	\$ (1,352,407)	\$ 353	\$ (1,352,054)
16	Distribution	\$ (3,493,008)	\$ -	\$ (3,493,008)
17	General	\$ (890,841)	\$ 1,629	\$ (889,212)
18	Intangible	\$ (494,766)	\$ -	\$ (494,766)
19	Subtotal Accumulated Depreciation	\$ (13,092,197)	\$ 21,423	\$ (13,070,774)
20	Nuclear Fuel Amortization	\$ (397,574)	\$ -	\$ (397,574)
21	Total Accumulated Depreciation	\$ (13,489,771)	\$ 21,423	\$ (13,468,348)
Accumulated Deferred Income Taxes				
22	Account 190	\$ 583,107	\$ 1,633	\$ 584,740
23	Account 281	\$ (776,938)	\$ -	\$ (776,938)
24	Account 282	\$ (5,214,008)	\$ 8,476	\$ (5,205,533)
25	Account 283	\$ (591,059)	\$ -	\$ (591,059)
26	Accumulated Deferred Income Taxes	\$ (5,998,898)	\$ 10,109	\$ (5,988,790)
Other Rate Base Items				
27	Fuel and Materials and Supplies	\$ 712,706	\$ (866)	\$ 711,840
28	Payables Associated with Capital M&S	\$ (1,572)	\$ -	\$ (1,572)
29	Minimum Bank Balances, Prepaids	\$ 88,787	\$ (989)	\$ 87,798
30	Prepaid Pension Asset	\$ 1,364,858	\$ -	\$ 1,364,858
31	Customer Deposits	\$ (292,009)	\$ -	\$ (292,009)
32	Accumulated Interest on Customer Deposits	\$ (34,019)	\$ -	\$ (34,019)
33	Operating Reserves	\$ (290,638)	\$ (5,685)	\$ (296,323)
34	Environmental CWIP	\$ 10,902	\$ -	\$ 10,902
35	Retired Units NBV	\$ 500,324	\$ -	\$ 500,324
36	Tax Reform Regulatory Liability	\$ (332,344)	\$ -	\$ (332,344)
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 6,385	\$ -	\$ 6,385
38	Unusable Inventory Regulatory Asset	\$ 22,255	\$ -	\$ 22,255
39	Future Nuclear Regulatory Asset	\$ 24,393	\$ -	\$ 24,393
40	Deferred Nuclear Outage Cost	\$ 41,406	\$ -	\$ 41,406
41	ARO Regulatory Asset (182)	\$ 3,580,399	\$ -	\$ 3,580,399
42	ARO Liability (230)	\$ (5,757,039)	\$ -	\$ (5,757,039)
43	ARO Regulatory Liability (254)	\$ 360,907	\$ (166)	\$ 360,741
44	Cash Working Capital	\$ (28,133)	\$ (1,700)	\$ (29,833)
45	Total Other Rate Base Items	\$ (22,433)	\$ (9,406)	\$ (31,839)
46	Total Rate Base	\$ 21,797,091	\$ (124,482)	\$ 21,672,609

Notes and Source

Col.A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 7 of 10

Georgia Power Company  
Adjusted Rate Base  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule B  
Page 4 of 4

Calendar Year 2022  
(Thousands of Dollars)

Line No.	Description	Original Cost		
		As Adjusted by Company	Staff Adjustments	As Adjusted by Staff
		(A)	(B)	(C)
<b>Plant-in-Service</b>				
1	Steam	\$ 9,905,027	\$ (61,980)	\$ 9,843,047
2	Nuclear	\$ 5,190,981	\$ -	\$ 5,190,981
3	Hydro	\$ 1,075,872	\$ (230,512)	\$ 845,360
4	Other CTs	\$ 3,811,732	\$ 36,465	\$ 3,848,198
5	Total Production	\$ 19,983,612	\$ (256,026)	\$ 19,727,586
6	Transmission	\$ 7,037,062	\$ 14,726	\$ 7,051,788
7	Distribution	\$ 12,468,758	\$ -	\$ 12,468,758
8	General	\$ 2,045,082	\$ (9,418)	\$ 2,035,664
9	Intangible	\$ 758,725	\$ (84)	\$ 758,641
10	Total Gross Plant	\$ 42,293,240	\$ (250,803)	\$ 42,042,437
11	Nuclear Fuel	\$ 755,122	\$ -	\$ 755,122
12	Electric Plant Held for Future Use	\$ 116,714	\$ -	\$ 116,714
13	Total Electric Plant	\$ 43,165,076	\$ (250,803)	\$ 42,914,273
<b>Accumulated Depreciation</b>				
14	Production	\$ (7,439,647)	\$ 22,071	\$ (7,417,576)
15	Transmission	\$ (1,413,938)	\$ 265	\$ (1,413,673)
16	Distribution	\$ (3,678,256)	\$ -	\$ (3,678,256)
17	General	\$ (922,299)	\$ 2,364	\$ (919,936)
18	Intangible	\$ (557,367)	\$ -	\$ (557,367)
19	Subtotal Accumulated Depreciation	\$ (14,011,507)	\$ 24,700	\$ (13,986,808)
20	Nuclear Fuel Amortization	\$ (404,061)	\$ -	\$ (404,061)
21	Total Accumulated Depreciation	\$ (14,415,568)	\$ 24,700	\$ (14,390,869)
<b>Accumulated Deferred Income Taxes</b>				
22	Account 190	\$ 523,325	\$ 544	\$ 523,869
23	Account 281	\$ (748,613)	\$ -	\$ (748,613)
24	Account 282	\$ (5,298,725)	\$ 8,810	\$ (5,289,915)
25	Account 283	\$ (534,946)	\$ -	\$ (534,946)
26	Accumulated Deferred Income Taxes	\$ (6,058,958)	\$ 9,354	\$ (6,049,605)
<b>Other Rate Base Items</b>				
27	Fuel and Materials and Supplies	\$ 725,611	\$ (671)	\$ 724,939
28	Payables Associated with Capital M&S	\$ (1,602)	\$ -	\$ (1,602)
29	Minimum Bank Balances, Prepaids	\$ 88,702	\$ (890)	\$ 87,812
30	Prepaid Pension Asset	\$ 1,408,516	\$ -	\$ 1,408,516
31	Customer Deposits	\$ (298,513)	\$ -	\$ (298,513)
32	Accumulated Interest on Customer Deposits	\$ (34,632)	\$ -	\$ (34,632)
33	Operating Reserves	\$ (461,095)	\$ (1,358)	\$ (462,453)
34	Environmental CWIP	\$ 3,634	\$ -	\$ 3,634
35	Retired Units NBV	\$ 433,275	\$ -	\$ 433,275
36	Tax Reform Regulatory Liability	\$ (110,781)	\$ -	\$ (110,781)
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 2,128	\$ -	\$ 2,128
38	Unusable Inventory Regulatory Asset	\$ 7,418	\$ -	\$ 7,418
39	Future Nuclear Regulatory Asset	\$ 8,131	\$ -	\$ 8,131
40	Deferred Nuclear Outage Cost	\$ 46,235	\$ -	\$ 46,235
41	ARO Regulatory Asset (182)	\$ 3,369,316	\$ -	\$ 3,369,316
42	ARO Liability (230)	\$ (5,472,532)	\$ -	\$ (5,472,532)
43	ARO Regulatory Liability (254)	\$ 478,976	\$ (295)	\$ 478,681
44	Cash Working Capital	\$ (34,989)	\$ 500	\$ (34,489)
45	Total Other Rate Base Items	\$ 157,795	\$ (2,714)	\$ 155,082
46	Total Rate Base	\$ 22,848,345	\$ (219,464)	\$ 22,628,881

Notes and Source

Col.A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 9 of 10

Line No.	Description	Staff Adjustments (A)	Adjustments to					Executive Financial Planning E-6	Property Tax Adjustment E-7	Interest Synchronization E-8	Stock-Based Compensation E-9	Payroll Tax Expense E-10	Uncollectibles Expense E-11	Storm Damage Accrual E-12	
			Rate Base Per Filing E-1	Operating Income Per GPC's Errata Filing E-2	Interest Credits on Minimum Bank Balances E-3	EV Charging Facilities E-4	Cash Working Capital E-5								
<b>Plant-in-Service</b>															
1	Steam	\$ (25,098)	\$ (25,098)												
2	Nuclear	\$ -													
3	Hydro	\$ (6,139)	\$ (6,139)												
4	Other CTs	\$ -													
5	Total Production	\$ (31,237)	\$ (31,237)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
6	Transmission	\$ (417)	\$ (417)												
7	Distribution	\$ -													
8	General	\$ (4,316)	\$ (222)			\$ (4,094)									
9	Intangible	\$ (47)	\$ (47)												
10	Total Gross Plant	\$ (36,017)	\$ (31,923)	\$ -	\$ -	\$ (4,094)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
11	Nuclear Fuel	\$ -													
12	Electric Plant Held for Future Use	\$ -													
13	Total Electric Plant	\$ (36,017)	\$ (31,923)	\$ -	\$ -	\$ (4,094)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
<b>Accumulated Depreciation</b>															
14	Production	\$ 10,023	\$ 10,023												
15	Transmission	\$ 181	\$ 181												
16	Distribution	\$ -													
17	General	\$ 637	\$ 346			\$ 291									
18	Intangible	\$ -													
19	Subtotal Accumulated Depreciation	\$ 10,841	\$ 10,550	\$ -	\$ -	\$ 291	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
20	Nuclear Fuel Amortization	\$ -													
21	Total Accumulated Depreciation	\$ 10,841	\$ 10,550	\$ -	\$ -	\$ 291	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
<b>Accumulated Deferred Income Taxes</b>															
22	Account 190	\$ 3,071											\$ 3,071		
23	Account 281	\$ -													
24	Account 282	\$ 4,570	\$ 3,931			\$ 639									
25	Account 283	\$ -													
26	Accumulated Deferred Income Taxes	\$ 7,641	\$ 3,931	\$ -	\$ -	\$ 639	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,071	
<b>Other Rate Base Items</b>															
27	Fuel and Materials and Supplies	\$ (517)	\$ (493)			\$ (24)									
28	Payables Associated with Capital M&S	\$ -													
29	Minimum Bank Balances, Prepaids	\$ (521)	\$ (521)												
30	Prepaid Pension Asset	\$ -													
31	Customer Deposits	\$ -													
32	Accumulated Interest on Customer Deposits	\$ -													
33	Operating Reserves	\$ (11,725)	\$ 416										\$ (12,141)		
34	Environmental CWIP	\$ -													
35	Retired Units NBV	\$ -													
36	Tax Reform Regulatory Liability	\$ -													
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ -													
38	Unusable Inventory Regulatory Asset	\$ -													
39	Future Nuclear Outage Costs	\$ -													
40	Deferred Nuclear Outage Cost	\$ -													
41	ARO Regulatory Asset (182)	\$ -													
42	ARO Liability (230)	\$ -													
43	ARO Regulatory Liability (254)	\$ 38	\$ 38			\$ (3,600)									
44	Cash Working Capital	\$ (3,600)													
45	Total Other Rate Base Items	\$ (16,325)	\$ (560)	\$ -	\$ -	\$ (24)	\$ (3,600)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (12,141)	
46	Total Rate Base	\$ (33,860)	\$ (18,002)	\$ -	\$ -	\$ (3,188)	\$ (3,600)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (9,070)	

Line No.	Description	Staff Adjustments (A)	Adjustments to Rate Base				Adjustments to Operating Income		Interest Credits on Minimum Bank Balances	EV Charging Facilities	Cash Working Capital	Executive Financial Planning	Property Tax Adjustment	Interest Synchronization	Stock-Based Compensation	Payroll Tax Expense	Uncollectibles Expense	Storm Damage Accrual
			E-1 Errata Filing	E-2 Filing	E-2 Per GPC's Errata	E-2 Filing	E-3 Bank Balances	E-4 Facilities										
Plant-in-Service																		
1	Steam	\$ (42,482)	\$ (42,482)															
2	Nuclear	\$ -																
3	Hydro	\$ (15,195)	\$ (15,195)															
4	Other C's	\$ -																
5	Total Production	\$ (57,677)	\$ (57,677)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
6	Transmission	\$ (715)	\$ (715)															
7	Distribution	\$ -																
8	General	\$ (5,318)	\$ (385)															
9	Intangible	\$ (80)	\$ (80)															
10	Total Gross Plant	\$ (63,790)	\$ (58,857)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
11	Nuclear Fuel	\$ -																
12	Electric Plant Held for Future Use	\$ -																
13	Total Electric Plant	\$ (63,790)	\$ (58,857)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Accumulated Depreciation																		
14	Production	\$ 17,168	\$ 17,168															
15	Transmission	\$ 312	\$ 312															
16	Distribution	\$ -																
17	General	\$ 970	\$ 628															
18	Intangible	\$ -																
19	Subtotal Accumulated Depreciation	\$ 18,450	\$ 18,108	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
20	Nuclear Fuel Amortization	\$ -																
21	Total Accumulated Depreciation	\$ 18,450	\$ 18,108	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Accumulated Deferred Income Taxes																		
22	Account 190	\$ 2,722															\$ 2,722	
23	Account 281	\$ -																
24	Account 282	\$ 7,559	\$ 6,846															
25	Account 283	\$ -																
26	Accumulated Deferred Income Taxes	\$ 10,281	\$ 6,846	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,722
Other Rate Base Items																		
27	Fuel and Materials and Supplies	\$ (839)	\$ (815)															
28	Payables Associated with Capital M&S	\$ -																
29	Minimum Bank Balances, Prepaids	\$ (904)	\$ (904)															
30	Prepaid Pension Asset	\$ -																
31	Customer Deposits	\$ -																
32	Accumulated Interest on Customer Deposits	\$ -																
33	Operating Reserves	\$ (10,049)	\$ 713														\$ (10,762)	
34	Environmental CWIP	\$ -																
35	Retired Units NBV	\$ -																
36	Tax Reform Regulatory Liability	\$ -																
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ -																
38	Unusable Inventory Regulatory Asset	\$ -																
39	Future Nuclear Outage Costs	\$ -																
40	Deferred Nuclear Outage Cost	\$ -																
41	ARO Regulatory Asset (182)	\$ -																
42	ARO Liability (230)	\$ -																
43	ARO Regulatory Liability (254)	\$ (6)	\$ (6)															
44	Cash Working Capital	\$ (3,100)	\$ (3,100)															
45	Total Other Rate Base Items	\$ (14,898)	\$ (1,012)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (10,762)
46	Total Rate Base	\$ (49,956)	\$ (34,914)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (8,040)



[illegible]



Georgia Power Company  
Adjusted Net Operating Income  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule C  
Page 1 of 4

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,222,674	\$ (2,173)	\$ 7,220,502
2	Other Operating Revenues	\$ 202,022	\$ (2,102)	\$ 199,920
3	Total Operating Revenues	\$ 7,424,697	\$ (4,275)	\$ 7,420,422
<b>Operating Expenses</b>				
4	Operations & Maintenance	\$ 4,362,948	\$ (24,922)	\$ 4,338,026
5	Depreciation	\$ 1,206,613	\$ (1,168)	\$ 1,205,445
6	Nuclear Decommissioning Expense	\$ 4,338	\$ -	\$ 4,338
7	Amortization of Investment Tax Credits	\$ (8,948)	\$ -	\$ (8,948)
8	Amortization of Obsolete Inventory	\$ 14,837	\$ -	\$ 14,837
9	Amortization of State Tax Reform Refund	\$ (1,231)	\$ -	\$ (1,231)
10	Amortization of Environmental CWIP	\$ 7,268	\$ -	\$ 7,268
11	Amortization of Retired Units' Net Book Value	\$ 68,762	\$ -	\$ 68,762
12	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ -	\$ 4,256
13	Amortization of Future Nuclear	\$ 16,262	\$ -	\$ 16,262
14	Taxes Other Than Income Taxes	\$ 268,630	\$ (4,146)	\$ 264,484
15	Subtotal Expenses	\$ 5,943,734	\$ (30,236)	\$ 5,913,498
16	Income Taxes	\$ 26,021	\$ (2,067)	\$ 23,955
17	Deferred Income Taxes	\$ -	\$ -	\$ -
18	Total Expenses	\$ 5,969,756	\$ (32,303)	\$ 5,937,453
19	Operating Income	\$ 1,454,941	\$ 28,028	\$ 1,482,969
20	Interest Expense (net of tax)	\$ (6,350)	\$ -	\$ (6,350)
21	Net Income	\$ 1,448,591	\$ 28,028	\$ 1,476,618

Notes and Source

Col. A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 4 of 10

Col. B: Staff Schedule C.1

Georgia Power Company  
Adjusted Net Operating Income  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule C  
Page 2 of 4

Calendar Year 2020  
(Thousands of Dollars)

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,216,665	\$ (3,676)	\$ 7,212,989
2	Other Operating Revenues	\$ 206,015	\$ (2,109)	\$ 203,906
3	Total Operating Revenues	<u>\$ 7,422,680</u>	<u>\$ (5,785)</u>	<u>\$ 7,416,895</u>
<b>Operating Expenses</b>				
4	Operations & Maintenance	\$ 4,399,505	\$ (22,762)	\$ 4,376,743
5	Depreciation	\$ 1,237,774	\$ (1,863)	\$ 1,235,911
6	Nuclear Decommissioning Expense	\$ 4,338	\$ -	\$ 4,338
7	Amortization of Investment Tax Credits	\$ (8,853)	\$ -	\$ (8,853)
8	Amortization of Obsolete Inventory	\$ 14,837	\$ -	\$ 14,837
9	Amortization of State Tax Reform Refund	\$ (1,231)	\$ -	\$ (1,231)
10	Amortization of Environmental CWIP	\$ 7,268	\$ -	\$ 7,268
11	Amortization of Retired Units' Net Book Value	\$ 68,762	\$ -	\$ 68,762
12	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ -	\$ 4,256
13	Amortization of Future Nuclear	\$ 16,262	\$ -	\$ 16,262
14	Taxes Other Than Income Taxes	\$ 275,160	\$ (4,199)	\$ 270,961
15	Subtotal Expenses	<u>\$ 6,018,078</u>	<u>\$ (28,824)</u>	<u>\$ 5,989,254</u>
16	Income Taxes	\$ 7,400	\$ (1,981)	\$ 5,419
17	Deferred Income Taxes	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
18	Total Expenses	<u>\$ 6,025,478</u>	<u>\$ (30,805)</u>	<u>\$ 5,994,673</u>
19	Operating Income	\$ 1,397,202	\$ 25,020	\$ 1,422,222
20	Interest Expense (net of tax)	<u>\$ (6,409)</u>	<u>\$ -</u>	<u>\$ (6,409)</u>
21	Net Income	<u>\$ 1,390,793</u>	<u>\$ 25,020</u>	<u>\$ 1,415,813</u>

#### Notes and Source

Col. A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 6 of 10

Col. B: Staff Schedule C.1

Georgia Power Company  
Adjusted Net Operating Income  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule C  
Page 3 of 4

Calendar Year 2021  
(Thousands of Dollars)

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,401,029	\$ (6,687)	\$ 7,394,342
2	Other Operating Revenues	\$ 211,372	\$ (2,113)	\$ 209,259
3	Total Operating Revenues	<u>\$ 7,612,402</u>	<u>\$ (8,801)</u>	<u>\$ 7,603,601</u>
<b>Operating Expenses</b>				
4	Operations & Maintenance	\$ 4,615,457	\$ (25,938)	\$ 4,589,519
5	Depreciation	\$ 1,421,954	\$ (4,094)	\$ 1,417,860
6	Nuclear Decommissioning Expense	\$ 4,338	\$ -	\$ 4,338
7	Amortization of Investment Tax Credits	\$ (8,846)	\$ -	\$ (8,846)
8	Amortization of Obsolete Inventory	\$ 14,837	\$ -	\$ 14,837
9	Amortization of State Tax Reform Refund	\$ (1,231)	\$ -	\$ (1,231)
10	Amortization of Environmental CWIP	\$ 7,268	\$ -	\$ 7,268
11	Amortization of Retired Units' Net Book Value	\$ 67,049	\$ -	\$ 67,049
12	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ -	\$ 4,256
13	Amortization of Future Nuclear	\$ 16,262	\$ -	\$ 16,262
14	Taxes Other Than Income Taxes	\$ 284,628	\$ (4,420)	\$ 280,207
15	Subtotal Expenses	<u>\$ 6,425,972</u>	<u>\$ (34,453)</u>	<u>\$ 6,391,519</u>
16	Income Taxes	\$ (49,413)	\$ 2,464	\$ (46,949)
17	Deferred Income Taxes	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
18	Total Expenses	<u>\$ 6,376,559</u>	<u>\$ (31,989)</u>	<u>\$ 6,344,570</u>
19	Operating Income	\$ 1,235,842	\$ 23,188	\$ 1,259,031
20	Interest Expense (net of tax)	<u>\$ (6,552)</u>	<u>\$ -</u>	<u>\$ (6,552)</u>
21	Net Income	<u>\$ 1,229,291</u>	<u>\$ 23,188</u>	<u>\$ 1,252,479</u>

#### Notes and Source

Col. A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 8 of 10

Col. B: Staff Schedule C.1

Georgia Power Company  
Adjusted Net Operating Income  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule C  
Page 4 of 4

Calendar Year 2022  
(Thousands of Dollars)

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,559,183	\$ (10,211)	\$ 7,548,972
2	Other Operating Revenues	\$ 212,685	\$ (2,116)	\$ 210,568
3	Total Operating Revenues	\$ 7,771,868	\$ (12,327)	\$ 7,759,541
<b>Operating Expenses</b>				
4	Operations & Maintenance	\$ 4,737,728	\$ (27,097)	\$ 4,710,631
5	Depreciation	\$ 1,692,238	\$ (6,862)	\$ 1,685,376
6	Nuclear Decommissioning Expense	\$ 4,338	\$ -	\$ 4,338
7	Amortization of Investment Tax Credits	\$ (11,214)	\$ -	\$ (11,214)
8	Amortization of Obsolete Inventory	\$ 14,837	\$ -	\$ 14,837
9	Amortization of State Tax Reform Refund	\$ (1,231)	\$ -	\$ (1,231)
10	Amortization of Environmental CWIP	\$ 7,268	\$ -	\$ 7,268
11	Amortization of Retired Units' Net Book Value	\$ 67,052	\$ -	\$ 67,052
12	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ -	\$ 4,256
13	Amortization of Future Nuclear	\$ 16,262	\$ -	\$ 16,262
14	Taxes Other Than Income Taxes	\$ 296,118	\$ (5,565)	\$ 290,553
15	Subtotal Expenses	\$ 6,827,652	\$ (39,525)	\$ 6,788,127
16	Income Taxes	\$ (86,547)	\$ 7,458	\$ (79,088)
17	Deferred Income Taxes	\$ -	\$ -	\$ -
18	Total Expenses	\$ 6,741,106	\$ (32,067)	\$ 6,709,039
19	Operating Income	\$ 1,030,762	\$ 19,739	\$ 1,050,502
20	Interest Expense (net of tax)	\$ (6,697)	\$ -	\$ (6,697)
21	Net Income	\$ 1,024,065	\$ 19,739	\$ 1,043,804

Notes and Source

Col. A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), Page 10 of 10

Col. B: Staff Schedule C.1

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Company Errata -												
		Staff Adjustments	Company Errata - Rate Base Adjustments	Operating Income	Interest Credits on Minimum Bank Balances	EV Charging Facilities	Cash Working Capital	Executive Financial Planning	Property Tax Expense	Interest Synchronization	Stock-Based Compensation	Payroll Tax Expense	Uncollectibles Expense	Storm Damage Accrual
		E-1	E-2	E-3	E-4	E-5	E-6	E-7	E-8	E-9	E-10	E-11	E-12	
<b>Operating Revenues</b>														
1	Electric Retail Revenues	\$ (2,173)	\$ (2,173)											
2	Other Operating Revenues	\$ (2,102)	\$ (1,995)	\$ (107)										
3	Total Operating Revenues	\$ (4,275)	\$ (4,168)	\$ -	\$ (107)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Operating Expenses</b>														
4	Operations and Maintenance Expense	\$ (24,922)	\$ 1,294	\$ (272)	\$ (321)	\$ (321)	\$ (409)			\$ (19,482)	\$ (1,427)	\$ (4,305)		
5	Depreciation	\$ (1,168)	\$ (1,081)		\$ (87)									
6	Nuclear Decommissioning Expense	\$ -												
7	Amortization of Investment Tax Credits	\$ -												
8	Amortization of Obsolete Inventory	\$ -												
9	Amortization of State Tax Reform Refund	\$ -												
10	Amortization of Environmental CWIP	\$ -												
11	Amortization of Retired Units' Net Book Value	\$ -												
12	Amortization of Deferred Healthcare Costs	\$ -												
13	Amortization of Future Nuclear	\$ -												
14	Taxes Other Than Income Taxes	\$ (4,146)	\$ (81)					\$ (2,575)		\$ (19,482)	\$ (1,490)			
15	PRE-TAX OPERATING EXPENSES	\$ (30,236)	\$ -	\$ (272)	\$ (408)	\$ -	\$ (409)	\$ (2,575)	\$ -	\$ (19,482)	\$ (1,490)	\$ (1,427)	\$ (4,305)	
16	PRE-TAX OPERATING INCOME	\$ 25,961	\$ (4,299)	\$ 272	\$ 301	\$ -	\$ 409	\$ 2,575	\$ -	\$ 19,482	\$ 1,490	\$ 1,427	\$ 4,305	
17	Income Taxes	\$ (2,067)	\$ -	\$ (1,005)	\$ 69	\$ -	\$ 103	\$ 651	\$ (8,716)	\$ 4,928	\$ 377	\$ 361	\$ 1,089	
18	Deferred Income Taxes	\$ -												
19	TOTAL OPERATING EXPENSES	\$ (32,303)	\$ (873)	\$ (203)	\$ (332)	\$ -	\$ (306)	\$ (1,924)	\$ (8,716)	\$ (14,554)	\$ (1,113)	\$ (1,066)	\$ (3,216)	
20	Interest Expense (net of tax)	\$ -												
21	OPERATING INCOME	\$ 28,028	\$ (3,295)	\$ 203	\$ 225	\$ -	\$ 306	\$ 1,924	\$ 8,716	\$ 14,554	\$ 1,113	\$ 1,066	\$ 3,216	

Notes and Source  
Combined Effective Tax Rate\* 25.296%  
\* Per Company filing, Exhibit (LIP/EL S-1, Schedule 1 Traditional Base)

Calendar Year 2020  
(Thousands of Dollars)

Line No.	Description	Company Errata -																							
		Company Errata - Rate Base		Operating Income		Interest Credits on Minimum Bank Balances		EV Charging Facilities		Cash Working Capital		Executive Financial Planning		Property Tax Expense		Synchronization		Stock-Based Compensation		Payroll Tax Expense		Uncollectibles Expense		Storm Damage Accrual	
		E-1	Adjustments	E-2	Adjustments	E-3	Bank Balances	E-4	Facilities	E-5	Capital	E-6	Planning	E-7	Expense	E-8	Interest	E-9	Compensation	E-10	Expense	E-11	Expense	E-12	Accrual
<b>Operating Revenues</b>																									
1	Electric Retail Revenues	\$	(3,676)	\$	(3,676)																				
2	Other Operating Revenues	\$	(2,109)	\$	(1,995)	\$	(114)																		
3	Total Operating Revenues	\$	(5,785)	\$	(5,671)	\$	(114)																		
<b>Operating Expenses</b>																									
4	Operations and Maintenance	\$	(22,762)	\$	3,933	\$	(272)	\$	(330)		\$	(409)						\$	(19,402)						
5	Depreciation	\$	(1,863)	\$	(1,730)			\$	(133)																
6	Nuclear Decommissioning Expense	\$	-																						
7	Amortization of Investment Tax Credits	\$	-																						
8	Amortization of Obsolete Inventory	\$	-																						
9	Amortization of State Tax Reform Refund	\$	-																						
10	Amortization of Environmental CWIP	\$	-																						
11	Amortization of Retired Units' Net Book Value	\$	-																						
12	Amortization of Deferred Healthcare Costs	\$	-																						
13	Amortization of Future Nuclear	\$	-																						
14	Taxes Other Than Income Taxes	\$	(4,199)		\$	(140)								\$	(2,575)				\$	(1,484)					
15	PRE-TAX OPERATING EXPENSES	\$	(28,824)	\$	-	\$	(2,063)	\$	(272)	\$	(463)	\$	(409)	\$	(2,575)	\$	-	\$	(19,402)	\$	(1,484)	\$	(1,978)	\$	(4,305)
16	PRE-TAX OPERATING INCOME	\$	23,039	\$	-	\$	(7,735)	\$	272	\$	349	\$	409	\$	2,575	\$	-	\$	19,402	\$	1,484	\$	1,978	\$	4,305
17	Income Taxes	\$	(1,981)		\$	(1,762)	\$	69	\$	88		\$	103	\$	651	\$	(8,002)	\$	4,908	\$	375	\$	500	\$	1,089
18	Deferred Income Taxes	\$	-																						
19	TOTAL OPERATING EXPENSES	\$	(30,805)		\$	302	\$	(203)	\$	(375)	\$	(306)	\$	(1,924)	\$	(8,002)	\$	(14,494)	\$	(1,109)	\$	(1,478)	\$	(3,216)	
20	Interest Expense (net of tax)	\$	-																						
21	OPERATING INCOME	\$	25,020		\$	(5,973)	\$	203	\$	261		\$	306	\$	1,924	\$	8,002	\$	14,494	\$	1,109	\$	1,478	\$	3,216

Notes and Source

Combined Effective Tax Rate\* 25.296%  
\* Per Company filing, Exhibit (LIP/ELS-1, Schedule 1 Traditional Base)

Calendar Year 2021  
(Thousands of Dollars)

Line No.	Description	Company Errata -																					
		Company Errata - Rate Base Adjustments		Operating Income Adjustments		Interest Credits on Minimum Bank Balances		EV Charging Facilities		Cash Working Capital		Executive Financial Planning		Property Tax Expense		Interest Synchronization		Stock-Based Compensation		Payroll Tax Expense		Uncollectibles Storm Damage Expense	
		E-1	E-2	E-3	E-4	E-5	E-6	E-7	E-8	E-9	E-10	E-11	E-12										
<b>Operating Revenues</b>																							
1	Electric Retail Revenues	\$ (6,687)	\$ (6,687)																				
2	Other Operating Revenues	\$ (2,113)	\$ (1,995)	\$ (118)																			
3	Total Operating Revenues	\$ (8,801)	\$ (8,683)	\$ -	\$ (118)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Operating Expenses</b>																							
4	Operations and Maintenance	\$ (25,938)	\$ 2,647	\$ (272)	\$ (338)		\$ (409)			\$ (21,283)		\$ (1,978)		\$ (4,305)									
5	Depreciation	\$ (4,094)	\$ (3,907)		\$ (187)																		
6	Nuclear Decommissioning Expense	\$ -																					
7	Amortization of Investment Tax Credits	\$ -																					
8	Amortization of Obsolete Inventory	\$ -																					
9	Amortization of State Tax Reform Refund	\$ -																					
10	Amortization of Environmental CWIP	\$ -																					
11	Amortization of Retired Units' Net Book Value	\$ -																					
12	Amortization of Deferred Healthcare Costs	\$ -																					
13	Amortization of Future Nuclear	\$ -	\$ (216)																				
14	Taxes Other Than Income Taxes	\$ (4,420)										\$ (2,575)		\$ (1,629)									
15	PRE-TAX OPERATING EXPENSES	\$ (34,453)	\$ (1,477)	\$ (272)	\$ (525)	\$ -	\$ (409)	\$ (2,575)		\$ (21,283)	\$ (1,629)	\$ (1,978)	\$ (4,305)										
16	PRE-TAX OPERATING INCOME	\$ 25,652	\$ (7,206)	\$ 272	\$ 407	\$ -	\$ 409	\$ 2,575		\$ 21,283	\$ 1,629	\$ 1,978	\$ 4,305										
17	Income Taxes	\$ 2,464	\$ (1,189)	\$ 69	\$ 103	\$ -	\$ 103	\$ 651		\$ 5,384	\$ 412	\$ 500	\$ 1,089										
18	Deferred Income Taxes	\$ -																					
19	TOTAL OPERATING EXPENSES	\$ (31,989)	\$ (2,666)	\$ (203)	\$ (422)	\$ -	\$ (306)	\$ (1,924)		\$ (15,899)	\$ (1,478)	\$ (3,216)											
20	Interest Expense (net of tax)	\$ -																					
21	OPERATING INCOME	\$ 23,188	\$ (6,016)	\$ 203	\$ 304	\$ -	\$ 306	\$ 1,924		\$ 4,658	\$ 1,217	\$ 1,478	\$ 3,216										

Notes and Source  
Combined Effective Tax Rate\* 25.296%  
\* Per Company filing, Exhibit (LIP/EL) S-1, Schedule 1 Traditional Base)

Calendar Year 2022  
(Thousands of Dollars)

Line No.	Description	Company Errata -													
		Company Errata -		Operating		Interest Credits		Executive		Financial		Stock-Based		Storm Damage	
		Staff Adjustments	Rate Base Adjustments	Income Adjustments	on Minimum Bank Balances	EV Charging Facilities	Cash Working Capital	Planning	Property Tax Expense	Synchronization	Interest	Compensation	Payroll Tax Expense	Uncollectibles Expense	Accrual
		E-1	E-2	E-3	E-4	E-5	E-6	E-7	E-8	E-9	E-10	E-11	E-12		
<b>Operating Revenues</b>															
1	Electric Retail Revenues	\$ (10,211)	\$ (10,211)												
2	Other Operating Revenues	\$ (2,116)	\$ (1,995)	\$ (121)											
3	Total Operating Revenues	\$ (12,327)	\$ (12,206)	\$ -	\$ (121)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
<b>Operating Expenses</b>															
4	Operations and Maintenance	\$ (27,097)	\$ 2,859	\$ (272)	\$ (347)		\$ (409)			\$ (22,644)		\$ (1,979)	\$ (4,305)		
5	Depreciation	\$ (6,862)	\$ (6,622)		\$ (240)										
6	Nuclear Decommissioning Expense	\$ -													
7	Amortization of Investment Tax Credits	\$ -													
8	Amortization of Obsolete Inventory	\$ -													
9	Amortization of State Tax Reform Refund	\$ -													
10	Amortization of Environmental CWIP	\$ -													
11	Amortization of Retired Units' Net Book Value	\$ -													
12	Amortization of Deferred Healthcare Costs	\$ -													
13	Amortization of Future Nuclear	\$ -													
14	Taxes Other Than Income Taxes	\$ (5,565)	\$ (1,258)					\$ (2,575)			\$ (1,732)				
15	PRE-TAX OPERATING EXPENSES	\$ (39,523)	\$ (5,022)	\$ (272)	\$ (587)	\$ -	\$ (409)	\$ (2,575)	\$ -	\$ (22,644)	\$ (1,732)	\$ (1,979)	\$ (4,305)		
16	PRE-TAX OPERATING INCOME	\$ 27,198	\$ (7,184)	\$ 272	\$ 466	\$ -	\$ 409	\$ 2,575	\$ 305	\$ 22,644	\$ 1,732	\$ 1,979	\$ 4,305		
17	Income Taxes	\$ 7,458	\$ (647)	\$ 69	\$ 118	\$ -	\$ 103	\$ 651	\$ (592)	\$ 5,728	\$ 438	\$ 501	\$ 1,089		
18	Deferred Income Taxes	\$ -													
19	TOTAL OPERATING EXPENSES	\$ (32,067)	\$ (5,669)	\$ (203)	\$ (469)	\$ -	\$ (306)	\$ (1,924)	\$ (592)	\$ (16,916)	\$ (1,294)	\$ (1,478)	\$ (3,216)		
20	Interest Expense (net of tax)	\$ -													
21	OPERATING INCOME	\$ 19,739	\$ (6,537)	\$ 203	\$ 348	\$ -	\$ 306	\$ 1,924	\$ 592	\$ 16,916	\$ 1,294	\$ 1,478	\$ 3,216		

Notes and Source

Combined Effective Tax Rate\* 25.296%  
\* Per Company filing, Exhibit (LIP/ELS-1, Schedule 1 Traditional Base)



Georgia Power Company  
Capital Structure & Cost Rates

Exhibit (RS/RT-2)  
Schedule D  
Page 1 of 4

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)	After-Tax Rate (E)	Revenue Requirement Rate (F)
<b>I. Company - Proposed</b>							
1	Long-Term Debt	\$ 11,752,692	43.92%	4.14%	1.82%	1.36%	1.82%
2	Common Stock Equity	\$ 15,009,316	56.08%	10.90%	6.11%	6.11%	8.18%
3	Total Capital	\$ 26,762,008	100.00%		7.93%	7.47%	10.00%
<b>II. Staff - Proposed</b>							
4	Long-Term Debt		49.00%	4.07%	1.99%	1.49%	1.99%
5	Common Stock Equity		51.00%	9.20%	4.69%	4.69%	6.28%
6	Total Capital		100.00%		6.69%	6.18%	8.28%
7	Difference				-1.25%		-1.73%
8	Weighted Cost of Debt				1.99%		

Notes and Source

Lines 1-3: Company Exhibit (DPP/SPA/MBR-3, Schedule 2, Workpaper 1)

Lines 4-8: Sponsored by Staff witness Michael Gorman

Georgia Power Company  
Capital Structure & Cost Rates  
Calendar 2020  
(Thousands of Dollars)

Exhibit (RS/RT-2)  
Schedule D  
Page 2 of 4

Line  
No.

Capital Source		Capitalization		Cost Rate (C)	Weighted Avg. Cost of Capital (D)	After-Tax Rate (E)	Revenue Requirement Rate (F)
No.	Capital Source	Amount (A)	Percent (B)	Rate (C)	Cost of Capital (D)	Rate (E)	Requirement Rate (F)
<b>I. Company - Proposed</b>							
1	Long-Term Debt	\$ 12,183,077	43.98%	4.26%	1.88%	1.40%	1.88%
2	Common Stock Equity	\$ 15,515,922	56.02%	10.90%	6.11%	6.11%	8.17%
3	Total Capital	\$ 27,699,000	100.00%		7.98%	7.51%	10.05%
<b>II. Staff - Proposed</b>							
4	Long-Term Debt		49.00%	4.15%	2.03%	1.52%	2.03%
5	Common Stock Equity		51.00%	9.20%	4.69%	4.69%	6.28%
6	Total Capital		100.00%		6.73%	6.21%	8.31%
7	Difference				-1.2561%		
8	Weighted Cost of Debt				2.03%		

Notes and Source

Lines 1-3: Company Exhibit (DPP/SPA/MBR-3, Schedule 2, Workpaper 2)  
Lines 4-8: Sponsored by Staff witness Michael Gorman

Georgia Power Company  
Capital Structure & Cost Rates  
Calendar 2021  
(Thousands of Dollars)

Line No.	Capital Source	Capitalization Amount (A)	Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)	After-Tax Rate (E)	Revenue Requirement Rate (F)
<b>I. Company - Proposed</b>							
1	Long-Term Debt	\$ 13,180,823	43.97%	4.47%	1.97%	1.47%	1.97%
2	Common Stock Equity	\$ 16,793,575	56.03%	10.90%	6.11%	6.11%	8.17%
3	Total Capital	\$ 29,974,398	100.00%		8.07%	7.58%	10.14%
<b>II. Staff - Proposed</b>							
4	Long-Term Debt		49.00%	4.21%	2.06%	1.54%	2.06%
5	Common Stock Equity		51.00%	9.20%	4.69%	4.69%	6.28%
6	Total Capital		100.00%		6.75%	6.23%	8.34%
7	Difference				-1.3186%		
8	Weighted Cost of Debt				2.06%		

Notes and Source

Lines 1-3: Company Exhibit (DPP/SPA/MBR-3, Schedule 2, Workpaper 3)

Lines 4-8: Sponsored by Staff witness Michael Gorman

Georgia Power Company  
Capital Structure & Cost Rates  
Calendar 2022  
(Thousands of Dollars)

Exhibit (RS/RT-2)  
Schedule D  
Page 4 of 4

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)	After-Tax Rate (E)	Revenue Requirement Rate (F)
<b>I. Company - Proposed</b>							
1	Long-Term Debt	\$ 14,105,627	43.97%	4.60%	2.02%	1.51%	2.02%
2	Common Stock Equity	\$ 17,972,984	56.03%	10.90%	6.11%	6.11%	8.17%
3	Total Capital	\$ 32,078,610	100.00%		8.13%	7.62%	10.20%
<b>II. Staff - Proposed</b>							
4	Long-Term Debt		49.00%	4.19%	2.05%	1.53%	2.05%
5	Common Stock Equity		51.00%	9.20%	4.69%	4.69%	6.28%
6	Total Capital		100.00%		6.75%	6.23%	8.33%
7	Difference				-1.3851%		
8	Weighted Cost of Debt				2.05%		

Notes and Source

Lines 1-3: Company Exhibit (DPP/SPA/MBR-3, Schedule 2, Workpaper 4)  
Lines 4-8: Sponsored by Staff witness Michael Gorman

Line No.	Description	Forecasted Test Year Ending 7/31/2020 (A)	Calendar 2020 (B)	Calendar 2021 (C)	Calendar 2022 (D)
<b>Plant-in-Service:</b>					
1	Steam	\$ (25,098)	\$ (42,482)	\$ (55,096)	\$ (61,980)
2	Hydro	\$ (6,139)	\$ (15,195)	\$ (84,658)	\$ (230,512)
3	Other Production	\$ -	\$ -	\$ 1,386	\$ 36,465
4	Transmission	\$ (417)	\$ (715)	\$ (774)	\$ 14,726
5	General	\$ (222)	\$ (385)	\$ (445)	\$ (485)
6	Intangible	\$ (47)	\$ (80)	\$ (87)	\$ (84)
7	<b>Total Electric Plant</b>	<b>\$ (31,923)</b>	<b>\$ (58,857)</b>	<b>\$ (139,674)</b>	<b>\$ (241,870)</b>
<b>Accumulated Depreciation:</b>					
8	Production	\$ 10,023	\$ 17,168	\$ 19,440	\$ 22,071
9	Transmission	\$ 181	\$ 312	\$ 353	\$ 265
10	General & Intangible	\$ 346	\$ 628	\$ 1,124	\$ 1,643
11	<b>Total Accumulated Depreciation</b>	<b>\$ 10,550</b>	<b>\$ 18,108</b>	<b>\$ 20,918</b>	<b>\$ 23,979</b>
12	<b>Net Plant-in-Service</b>	<b>\$ (21,373)</b>	<b>\$ (40,748)</b>	<b>\$ (118,757)</b>	<b>\$ (217,891)</b>
<b>Other Rate Base Items:</b>					
13	Fuel and Materials & Supplies Inventory	\$ (493)	\$ (815)	\$ (842)	\$ (647)
14	Min. Bank Balances, Prepayments	\$ (521)	\$ (904)	\$ (989)	\$ (890)
15	Operating Reserves	\$ 416	\$ 713	\$ 772	\$ 795
16	ARO Regulatory Liability (254)	\$ 38	\$ (6)	\$ (166)	\$ (295)
17	<b>Accumulated Deferred Income Taxes</b>	<b>\$ 3,931</b>	<b>\$ 6,846</b>	<b>\$ 7,527</b>	<b>\$ 7,567</b>
18	<b>Total Retail Rate Base</b>	<b>\$ (18,002)</b>	<b>\$ (34,914)</b>	<b>\$ (112,455)</b>	<b>\$ (211,362)</b>

Notes and Source

Cols. A-D: Amounts from the Company's Errata filing that was filed on September 24, 2019

Georgia Power Company  
Company Errata - Rate Base Adjustments  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-1  
Page 2 of 5

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Rate Base Per Errata (A)	As-Filed Retail Adjusted Rate Base (B)	Adjustment (C)
<b>Plant-in-Service</b>				
1	Steam	\$ 9,569,680	\$ 9,594,779	\$ (25,098)
2	Nuclear	\$ 5,040,284	\$ 5,040,284	\$ -
3	Hydro	\$ 806,925	\$ 813,064	\$ (6,139)
4	Other CTs	\$ 3,291,379	\$ 3,291,379	\$ -
5	Total Production	\$ 18,708,270	\$ 18,739,507	\$ (31,237)
6	Transmission	\$ 6,288,555	\$ 6,288,972	\$ (417)
7	Distribution	\$ 10,528,598	\$ 10,528,598	\$ -
8	General	\$ 1,616,141	\$ 1,616,363	\$ (222)
9	Intangible	\$ 582,574	\$ 582,621	\$ (47)
10	Total Gross Plant	\$ 37,724,138	\$ 37,756,061	\$ (31,923)
11	Nuclear Fuel	\$ 752,195	\$ 752,195	\$ -
12	Electric Plant Held for Future Use	\$ 116,714	\$ 116,714	\$ -
13	Total Electric Plant	\$ 38,593,048	\$ 38,624,971	\$ (31,923)
<b>Accumulated Depreciation</b>				
14	Production	\$ (6,152,933)	\$ (6,162,956)	\$ 10,023
15	Transmission	\$ (1,292,610)	\$ (1,292,791)	\$ 181
16	Distribution	\$ (3,264,298)	\$ (3,264,298)	\$ -
17	General	\$ (805,029)	\$ (805,328)	\$ 299
18	Intangible	\$ (419,572)	\$ (419,619)	\$ 47
19	Subtotal Accumulated Depreciation	\$ (11,934,443)	\$ (11,944,993)	\$ 10,550
20	Nuclear Fuel Amortization	\$ (390,219)	\$ (390,219)	\$ -
21	Total Accumulated Depreciation	\$ (12,324,661)	\$ (12,335,211)	\$ 10,550
<b>Accumulated Deferred Income Taxes</b>				
22	Account 190	\$ (819,142)	\$ 646,159	\$ (1,465,301)
23	Account 281	\$ (5,057,945)	\$ (819,142)	\$ (4,238,803)
24	Account 282	\$ (650,898)	\$ (5,061,956)	\$ 4,411,057
25	Account 283	\$ 645,901	\$ (651,076)	\$ 1,296,977
26	Accumulated Deferred Income Taxes	\$ (5,882,085)	\$ (5,886,015)	\$ 3,931
<b>Other Rate Base Items</b>				
27	Fuel and Materials and Supplies	\$ 702,577	\$ 703,070	\$ (493)
28	Payables Associated with Capital M&S	\$ (1,505)	\$ (1,505)	\$ -
29	Minimum Bank Balances, Prepaids	\$ 83,192	\$ 83,713	\$ (521)
30	Prepaid Pension Asset	\$ 1,320,397	\$ 1,320,397	\$ -
31	Customer Deposits	\$ (283,112)	\$ (283,112)	\$ -
32	Accumulated Interest on Customer Deposits	\$ (33,172)	\$ (33,172)	\$ -
33	Operating Reserves	\$ (152,319)	\$ (152,735)	\$ 416
34	Environmental CWIP	\$ 21,198	\$ 21,198	\$ -
35	Retired Units NBV	\$ 588,529	\$ 588,529	\$ -
36	Tax Reform Regulatory Liability	\$ (547,254)	\$ (547,254)	\$ -
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 12,414	\$ 12,414	\$ -
38	Unusable Inventory Regulatory Asset	\$ 37,092	\$ 37,092	\$ -
39	Future Nuclear Outage Costs	\$ 40,655	\$ 40,655	\$ -
40	Deferred Nuclear Outage Cost	\$ 39,217	\$ 39,217	\$ -
41	ARO Regulatory Asset (182)	\$ 3,579,099	\$ 3,579,099	\$ -
42	ARO Liability (230)	\$ (5,859,756)	\$ (5,859,756)	\$ -
43	ARO Regulatory Liability (254)	\$ 168,274	\$ 168,235	\$ 38
44	Cash Working Capital	\$ (22,482)	\$ (22,482)	\$ -
45	Total Other Rate Base Items	\$ (306,954)	\$ (306,395)	\$ (560)
46	Total Rate Base	\$ 20,079,348	\$ 20,097,349	\$ (18,002)

Notes and Source

Col. A: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 3

Col. B: Amounts from as-filed Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 3

Georgia Power Company  
Company Errata - Rate Base Adjustments  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-1  
Page 3 of 5

Calendar 2020  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Rate Base Per Errata (A)	As-Filed Retail Adjusted Rate Base (B)	Adjustment (C)
<b>Plant-in-Service</b>				
1	Steam	\$ 9,673,901	\$ 9,716,382	\$ (42,482)
2	Nuclear	\$ 5,061,671	\$ 5,061,671	\$ -
3	Hydro	\$ 812,430	\$ 827,625	\$ (15,195)
4	Other CTs	\$ 3,389,271	\$ 3,389,271	\$ -
5	Total Production	\$ 18,937,272	\$ 18,994,949	\$ (57,677)
6	Transmission	\$ 6,454,189	\$ 6,454,904	\$ (715)
7	Distribution	\$ 10,792,519	\$ 10,792,519	\$ -
8	General	\$ 1,720,013	\$ 1,720,398	\$ (385)
9	Intangible	\$ 598,228	\$ 598,308	\$ (80)
10	Total Gross Plant	\$ 38,502,222	\$ 38,561,078	\$ (58,857)
11	Nuclear Fuel	\$ 764,660	\$ 764,660	\$ -
12	Electric Plant Held for Future Use	\$ 116,714	\$ 116,714	\$ -
13	Total Electric Plant	\$ 39,383,596	\$ 39,442,452	\$ (58,857)
<b>Accumulated Depreciation</b>				
14	Production	\$ (6,298,311)	\$ (6,315,479)	\$ 17,168
15	Transmission	\$ (1,303,776)	\$ (1,304,088)	\$ 312
16	Distribution	\$ (3,322,520)	\$ (3,322,520)	\$ -
17	General	\$ (839,209)	\$ (839,756)	\$ 547
18	Intangible	\$ (440,131)	\$ (440,212)	\$ 81
19	Subtotal Accumulated Depreciation	\$ (12,203,947)	\$ (12,222,056)	\$ 18,108
20	Nuclear Fuel Amortization	\$ (392,145)	\$ (392,145)	\$ -
21	Total Accumulated Depreciation	\$ (12,596,092)	\$ (12,614,200)	\$ 18,108
<b>Accumulated Deferred Income Taxes</b>				
22	Account 190	\$ (803,149)	\$ 639,996	\$ (1,443,145)
23	Account 281	\$ (5,114,134)	\$ (803,149)	\$ (4,310,985)
24	Account 282	\$ (651,289)	\$ (5,121,141)	\$ 4,469,852
25	Account 283	\$ 639,555	\$ (651,569)	\$ 1,291,124
26	Accumulated Deferred Income Taxes	\$ (5,929,017)	\$ (5,935,863)	\$ 6,846
<b>Other Rate Base Items</b>				
27	Fuel and Materials and Supplies	\$ 713,333	\$ 714,148	\$ (815)
28	Payables Associated with Capital M&S	\$ (1,529)	\$ (1,529)	\$ -
29	Minimum Bank Balances, Prepaids	\$ 82,287	\$ 83,191	\$ (904)
30	Prepaid Pension Asset	\$ 1,331,914	\$ 1,331,914	\$ -
31	Customer Deposits	\$ (285,645)	\$ (285,645)	\$ -
32	Accumulated Interest on Customer Deposits	\$ (33,418)	\$ (33,418)	\$ -
33	Operating Reserves	\$ (131,936)	\$ (132,649)	\$ 713
34	Environmental CWIP	\$ 18,169	\$ 18,169	\$ -
35	Retired Units NBV	\$ 568,229	\$ 568,229	\$ -
36	Tax Reform Regulatory Liability	\$ (553,908)	\$ (553,908)	\$ -
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 10,641	\$ 10,641	\$ -
38	Unusable Inventory Regulatory Asset	\$ 37,092	\$ 37,092	\$ -
39	Future Nuclear Outage Costs	\$ 40,655	\$ 40,655	\$ -
40	Deferred Nuclear Outage Cost	\$ 42,323	\$ 42,323	\$ -
41	ARO Regulatory Asset (182)	\$ 3,602,132	\$ 3,602,132	\$ -
42	ARO Liability (230)	\$ (5,852,196)	\$ (5,852,196)	\$ -
43	ARO Regulatory Liability (254)	\$ 256,863	\$ 256,869	\$ (6)
44	Cash Working Capital	\$ (26,035)	\$ (26,035)	\$ -
45	Total Other Rate Base Items	\$ (181,028)	\$ (180,016)	\$ (1,012)
46	Total Rate Base	\$ 20,677,459	\$ 20,712,373	\$ (34,914)

Notes and Source

Col. A: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 5

Col. B: Amounts from as-filed Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 5

Georgia Power Company  
Company Errata - Rate Base Adjustments  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-1  
Page 4 of 5

Calendar 2021  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Rate Base Per Errata (A)	As-Filed Retail Adjusted Rate Base (B)	Adjustment (C)
<b>Plant-in-Service</b>				
1	Steam	\$ 9,761,473	\$ 9,816,569	\$ (55,096)
2	Nuclear	\$ 5,128,331	\$ 5,128,331	\$ -
3	Hydro	\$ 833,969	\$ 918,627	\$ (84,658)
4	Other CTs	\$ 3,699,435	\$ 3,698,049	\$ 1,386
5	Total Production	\$ 19,423,209	\$ 19,561,577	\$ (138,368)
6	Transmission	\$ 6,757,084	\$ 6,757,859	\$ (774)
7	Distribution	\$ 11,554,213	\$ 11,554,213	\$ -
8	General	\$ 1,916,202	\$ 1,916,647	\$ (445)
9	Intangible	\$ 666,825	\$ 666,912	\$ (87)
10	Total Gross Plant	\$ 40,317,534	\$ 40,457,208	\$ (139,674)
11	Nuclear Fuel	\$ 734,270	\$ 734,270	\$ -
12	Electric Plant Held for Future Use	\$ 116,714	\$ 116,714	\$ -
13	Total Electric Plant	\$ 41,168,519	\$ 41,308,193	\$ (139,674)
<b>Accumulated Depreciation</b>				
14	Production	\$ (6,841,734)	\$ (6,861,174)	\$ 19,440
15	Transmission	\$ (1,352,054)	\$ (1,352,407)	\$ 353
16	Distribution	\$ (3,493,008)	\$ (3,493,008)	\$ -
17	General	\$ (889,809)	\$ (890,841)	\$ 1,032
18	Intangible	\$ (494,674)	\$ (494,766)	\$ 92
19	Subtotal Accumulated Depreciation	\$ (13,071,279)	\$ (13,092,197)	\$ 20,918
20	Nuclear Fuel Amortization	\$ (397,574)	\$ (397,574)	\$ -
21	Total Accumulated Depreciation	\$ (13,468,853)	\$ (13,489,771)	\$ 20,918
<b>Accumulated Deferred Income Taxes</b>				
22	Account 190	\$ (776,938)	\$ 583,107	\$ (1,360,045)
23	Account 281	\$ (5,206,283)	\$ (776,938)	\$ (4,429,345)
24	Account 282	\$ (590,752)	\$ (5,214,008)	\$ 4,623,257
25	Account 283	\$ 582,601	\$ (591,059)	\$ 1,173,660
26	Accumulated Deferred Income Taxes	\$ (5,991,372)	\$ (5,998,898)	\$ 7,527
<b>Other Rate Base Items</b>				
27	Fuel and Materials and Supplies	\$ 711,864	\$ 712,706	\$ (842)
28	Payables Associated with Capital M&S	\$ (1,572)	\$ (1,572)	\$ -
29	Minimum Bank Balances, Prepaids	\$ 87,798	\$ 88,787	\$ (989)
30	Prepaid Pension Asset	\$ 1,364,858	\$ 1,364,858	\$ -
31	Customer Deposits	\$ (292,009)	\$ (292,009)	\$ -
32	Accumulated Interest on Customer Deposits	\$ (34,019)	\$ (34,019)	\$ -
33	Operating Reserves	\$ (289,866)	\$ (290,638)	\$ 772
34	Environmental CWIP	\$ 10,902	\$ 10,902	\$ -
35	Retired Units NBV	\$ 500,324	\$ 500,324	\$ -
36	Tax Reform Regulatory Liability	\$ (332,344)	\$ (332,344)	\$ -
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 6,385	\$ 6,385	\$ -
38	Unusable Inventory Regulatory Asset	\$ 22,255	\$ 22,255	\$ -
39	Future Nuclear Outage Costs	\$ 24,393	\$ 24,393	\$ -
40	Deferred Nuclear Outage Cost	\$ 41,406	\$ 41,406	\$ -
41	ARO Regulatory Asset (182)	\$ 3,580,399	\$ 3,580,399	\$ -
42	ARO Liability (230)	\$ (5,757,039)	\$ (5,757,039)	\$ -
43	ARO Regulatory Liability (254)	\$ 360,741	\$ 360,907	\$ (166)
44	Cash Working Capital	\$ (28,133)	\$ (28,133)	\$ -
45	Total Other Rate Base Items	\$ (23,658)	\$ (22,433)	\$ (1,225)
46	Total Rate Base	\$ 21,684,636	\$ 21,797,091	\$ (112,455)

Notes and Source

Col. A: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 7

Col. B: Amounts from as-filed Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 7



Georgia Power Company  
Company Errata - Rate Base Adjustments  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-1  
Page 5 of 5

Calendar 2022  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Rate Base Per Errata (A)	As-Filed Retail Adjusted Rate Base (B)	Adjustment (C)
<b>Plant-in-Service</b>				
1	Steam	\$ 9,843,047	\$ 9,905,027	\$ (61,980)
2	Nuclear	\$ 5,190,981	\$ 5,190,981	\$ -
3	Hydro	\$ 845,360	\$ 1,075,872	\$ (230,512)
4	Other CTs	\$ 3,848,198	\$ 3,811,732	\$ 36,465
5	Total Production	\$ 19,727,586	\$ 19,983,612	\$ (256,026)
6	Transmission	\$ 7,051,788	\$ 7,037,062	\$ 14,726
7	Distribution	\$ 12,468,758	\$ 12,468,758	\$ -
8	General	\$ 2,044,597	\$ 2,045,082	\$ (485)
9	Intangible	\$ 758,641	\$ 758,725	\$ (84)
10	Total Gross Plant	\$ 42,051,370	\$ 42,293,240	\$ (241,870)
11	Nuclear Fuel	\$ 755,122	\$ 755,122	\$ -
12	Electric Plant Held for Future Use	\$ 116,714	\$ 116,714	\$ -
13	Total Electric Plant	\$ 42,923,206	\$ 43,165,076	\$ (241,870)
<b>Accumulated Depreciation</b>				
14	Production	\$ (7,417,576)	\$ (7,439,647)	\$ 22,071
15	Transmission	\$ (1,413,673)	\$ (1,413,938)	\$ 265
16	Distribution	\$ (3,678,256)	\$ (3,678,256)	\$ -
17	General	\$ (920,738)	\$ (922,299)	\$ 1,562
18	Intangible	\$ (557,286)	\$ (557,367)	\$ 81
19	Subtotal Accumulated Depreciation	\$ (13,987,529)	\$ (14,011,507)	\$ 23,979
20	Nuclear Fuel Amortization	\$ (404,061)	\$ (404,061)	\$ -
21	Total Accumulated Depreciation	\$ (14,391,590)	\$ (14,415,568)	\$ 23,979
<b>Accumulated Deferred Income Taxes</b>				
22	Account 190	\$ (748,613)	\$ 523,325	\$ (1,271,938)
23	Account 281	\$ (5,290,967)	\$ (748,613)	\$ (4,542,354)
24	Account 282	\$ (534,626)	\$ (5,298,725)	\$ 4,764,098
25	Account 283	\$ 522,815	\$ (534,946)	\$ 1,057,761
26	Accumulated Deferred Income Taxes	\$ (6,051,392)	\$ (6,058,958)	\$ 7,567
<b>Other Rate Base Items</b>				
27	Fuel and Materials and Supplies	\$ 724,963	\$ 725,611	\$ (647)
28	Payables Associated with Capital M&S	\$ (1,602)	\$ (1,602)	\$ -
29	Minimum Bank Balances, Prepaids	\$ 87,812	\$ 88,702	\$ (890)
30	Prepaid Pension Asset	\$ 1,408,516	\$ 1,408,516	\$ -
31	Customer Deposits	\$ (298,513)	\$ (298,513)	\$ -
32	Accumulated Interest on Customer Deposits	\$ (34,632)	\$ (34,632)	\$ -
33	Operating Reserves	\$ (460,301)	\$ (461,095)	\$ 795
34	Environmental CWIP	\$ 3,634	\$ 3,634	\$ -
35	Retired Units NBV	\$ 433,275	\$ 433,275	\$ -
36	Tax Reform Regulatory Liability	\$ (110,781)	\$ (110,781)	\$ -
37	OPEB Ret. Drug Subs. Tax Reg. Asset	\$ 2,128	\$ 2,128	\$ -
38	Unusable Inventory Regulatory Asset	\$ 7,418	\$ 7,418	\$ -
39	Future Nuclear Outage Costs	\$ 8,131	\$ 8,131	\$ -
40	Deferred Nuclear Outage Cost	\$ 46,235	\$ 46,235	\$ -
41	ARO Regulatory Asset (182)	\$ 3,369,316	\$ 3,369,316	\$ -
42	ARO Liability (230)	\$ (5,472,532)	\$ (5,472,532)	\$ -
43	ARO Regulatory Liability (254)	\$ 478,681	\$ 478,976	\$ (295)
44	Cash Working Capital	\$ (34,989)	\$ (34,989)	\$ -
45	Total Other Rate Base Items	\$ 156,758	\$ 157,795	\$ (1,037)
46	Total Rate Base	\$ 22,636,982	\$ 22,848,345	\$ (211,362)

Notes and Source

Col. A: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 9

Col. B: Amounts from as-filed Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 9

Georgia Power Company  
Company Errata - Operating Income Adjustments  
Retail Electric Amounts

Staff Exhibit (RS/RT-2)  
Schedule E-2  
Page 1 of 4

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Operating Income Per Errata (A)	As-Filed Retail Operating Income (B)	Adjustment (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,220,502	\$ 7,222,674	\$ (2,173)
2	Other Operating Revenues	\$ 200,027	\$ 202,022	\$ (1,995)
3	Total Operating Revenues	<u>\$ 7,420,529</u>	<u>\$ 7,424,697</u>	<u>\$ (4,168)</u>
<b>Operating Expenses</b>				
4	Generation - Fixed	\$ 547,405	\$ 543,662	\$ 3,743
5	Generation - Fuel & Variable O&M	\$ 1,502,660	\$ 1,502,660	\$ -
6	Affiliated Purchased Power-Non-Fuel	\$ 122,490	\$ 122,490	\$ -
7	Affiliated Purchased Power-Fuel	\$ 466,755	\$ 466,755	\$ -
8	Non-Affiliated Purchased Power-Non-Fuel	\$ 148,635	\$ 148,635	\$ -
9	Non-Affiliated Purchased Power-Fuel	\$ 349,224	\$ 349,224	\$ -
10	System Control & Load Dispatching	\$ 33,225	\$ 33,225	\$ -
11	Transmission	\$ 129,991	\$ 129,992	\$ (1)
12	Distribution	\$ 277,977	\$ 277,977	\$ -
13	Customer Accounting	\$ 143,601	\$ 143,601	\$ -
14	Customer Assistance	\$ 110,625	\$ 113,031	\$ (2,406)
15	Energy Services	\$ 46,817	\$ 46,817	\$ -
16	Administrative & General	\$ 484,836	\$ 484,878	\$ (42)
17	Total Operations & Maintenance	<u>\$ 4,364,241</u>	<u>\$ 4,362,948</u>	<u>\$ 1,294</u>
<b>Depreciation and Amortization</b>				
18	Production	\$ 711,850	\$ 712,536	\$ (686)
19	Transmission	\$ 134,755	\$ 134,764	\$ (9)
20	Distribution	\$ 281,867	\$ 281,867	\$ -
21	General & Intangible	\$ 77,045	\$ 77,446	\$ (402)
22	Nuclear Decommissioning Expense	\$ 4,338	\$ 4,338	\$ -
23	Amortization of Investment Tax Credits	\$ (8,932)	\$ (8,948)	\$ 16
24	Amortization of Obsolete Inventory	\$ 14,837	\$ 14,837	\$ -
25	Amortization of State Tax Reform Refund	\$ (1,231)	\$ (1,231)	\$ -
26	Amortization of Environmental CWIP	\$ 7,268	\$ 7,268	\$ -
27	Amortization of Retired Units' Net Book Value	\$ 68,762	\$ 68,762	\$ -
28	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ 4,256	\$ -
29	Amortization of Future Nuclear	\$ 16,262	\$ 16,262	\$ -
30	Total Depreciation and Amortization	<u>\$ 1,311,075</u>	<u>\$ 1,312,157</u>	<u>\$ (1,081)</u>
31	Taxes Other Than Income Taxes	\$ 268,549	\$ 268,630	\$ (81)
32	Income Taxes	<u>\$ 25,017</u>	<u>\$ 26,021</u>	<u>\$ (1,005)</u>
33	Total Expenses	<u>\$ 5,968,883</u>	<u>\$ 5,969,756</u>	<u>\$ (873)</u>
34	Operating Income	\$ 1,451,646	\$ 1,454,941	\$ (3,295)
35	Interest on Customer Deposits	<u>\$ (6,350)</u>	<u>\$ (6,350)</u>	<u>\$ -</u>
36	Retail Earnings Available For Return	<u>\$ 1,445,296</u>	<u>\$ 1,448,591</u>	<u>\$ (3,295)</u>

Notes and Source

Col. A: Amounts from Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 4

Col. B: Amounts from as-filed Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company), page 4

Georgia Power Company  
Company Errata - Operating Income Adjustments  
Retail Electric Amounts

Staff Exhibit (RS/RT-2)  
Schedule E-2  
Page 2 of 4

Calendar 2020  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Operating Income Per Errata (A)	As-Filed Retail Operating Income (B)	Adjustment (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,212,989	\$ 7,216,665	\$ (3,676)
2	Other Operating Revenues	\$ 204,020	\$ 206,015	\$ (1,995)
3	Total Operating Revenues	<u>\$ 7,417,009</u>	<u>\$ 7,422,680</u>	<u>\$ (5,671)</u>
<b>Operating Expenses</b>				
4	Generation - Fixed	\$ 560,124	\$ 553,712	\$ 6,412
5	Generation - Fuel & Variable O&M	\$ 1,507,985	\$ 1,507,985	\$ -
6	Affiliated Purchased Power-Non-Fuel	\$ 122,598	\$ 122,598	\$ -
7	Affiliated Purchased Power-Fuel	\$ 448,603	\$ 448,603	\$ -
8	Non-Affiliated Purchased Power-Non-Fuel	\$ 148,344	\$ 148,344	\$ -
9	Non-Affiliated Purchased Power-Fuel	\$ 373,729	\$ 373,729	\$ -
10	System Control & Load Dispatching	\$ 33,416	\$ 33,416	\$ -
11	Transmission	\$ 127,845	\$ 127,846	\$ (1)
12	Distribution	\$ 275,930	\$ 275,930	\$ -
13	Customer Accounting	\$ 155,876	\$ 155,876	\$ -
14	Customer Assistance	\$ 112,130	\$ 114,536	\$ (2,406)
15	Energy Services	\$ 47,613	\$ 47,613	\$ -
16	Administrative & General	\$ 489,245	\$ 489,316	\$ (71)
17	Total Operations & Maintenance	<u>\$ 4,403,439</u>	<u>\$ 4,399,505</u>	<u>\$ 3,933</u>
<b>Depreciation and Amortization</b>				
18	Production	\$ 719,564	\$ 720,877	\$ (1,313)
19	Transmission	\$ 138,491	\$ 138,507	\$ (16)
20	Distribution	\$ 288,750	\$ 288,750	\$ -
21	General & Intangible	\$ 89,211	\$ 89,640	\$ (429)
22	Nuclear Decommissioning Expense	\$ 4,338	\$ 4,338	\$ -
23	Amortization of Investment Tax Credits	\$ (8,825)	\$ (8,853)	\$ 28
24	Amortization of Obsolete Inventory	\$ 14,837	\$ 14,837	\$ -
25	Amortization of State Tax Reform Refund	\$ (1,231)	\$ (1,231)	\$ -
26	Amortization of Environmental CWIP	\$ 7,268	\$ 7,268	\$ -
27	Amortization of Retired Units' Net Book Value	\$ 68,762	\$ 68,762	\$ -
28	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ 4,256	\$ -
29	Amortization of Future Nuclear	\$ 16,262	\$ 16,262	\$ -
30	Total Depreciation and Amortization	<u>\$ 1,341,682</u>	<u>\$ 1,343,412</u>	<u>\$ (1,730)</u>
31	Taxes Other Than Income Taxes	\$ 275,020	\$ 275,160	\$ (140)
32	Income Taxes	\$ 5,638	\$ 7,400	\$ (1,762)
33	Total Expenses	<u>\$ 6,025,779</u>	<u>\$ 6,025,478</u>	<u>\$ 302</u>
34	Operating Income	\$ 1,391,229	\$ 1,397,202	\$ (5,973)
35	Interest on Customer Deposits	\$ (6,409)	\$ (6,409)	\$ -
36	Retail Earnings Available For Return	<u>\$ 1,384,821</u>	<u>\$ 1,390,793</u>	<u>\$ (5,973)</u>

Notes and Source

Col. A: Amounts from Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 6

Col. B: Amounts from as-filed Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company), page 6

Georgia Power Company  
Company Errata - Operating Income Adjustments  
Retail Electric Amounts

Staff Exhibit (RS/RT-2)  
Schedule E-2  
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Calendar 2021  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Operating Income Per Errata (A)	As-Filed Retail Operating Income (B)	Adjustment (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,394,342	\$ 7,401,029	\$ (6,687)
2	Other Operating Revenues	\$ 209,377	\$ 211,372	\$ (1,995)
3	Total Operating Revenues	<u>\$ 7,603,719</u>	<u>\$ 7,612,402</u>	<u>\$ (8,683)</u>
<b>Operating Expenses</b>				
4	Generation - Fixed	\$ 581,770	\$ 575,767	\$ 6,003
5	Generation - Fuel & Variable O&M	\$ 1,630,136	\$ 1,630,136	\$ -
6	Affiliated Purchased Power-Non-Fuel	\$ 130,646	\$ 130,646	\$ -
7	Affiliated Purchased Power-Fuel	\$ 478,938	\$ 478,938	\$ -
8	Non-Affiliated Purchased Power-Non-Fuel	\$ 149,464	\$ 149,464	\$ -
9	Non-Affiliated Purchased Power-Fuel	\$ 387,107	\$ 387,107	\$ -
10	System Control & Load Dispatching	\$ 34,336	\$ 34,336	\$ -
11	Transmission	\$ 129,043	\$ 129,044	\$ (1)
12	Distribution	\$ 282,496	\$ 282,496	\$ -
13	Customer Accounting	\$ 158,034	\$ 158,034	\$ -
14	Customer Assistance	\$ 116,233	\$ 119,530	\$ (3,296)
15	Energy Services	\$ 49,077	\$ 49,077	\$ -
16	Administrative & General	\$ 490,826	\$ 490,885	\$ (59)
17	Total Operations & Maintenance	<u>\$ 4,618,103</u>	<u>\$ 4,615,457</u>	<u>\$ 2,647</u>
<b>Depreciation and Amortization</b>				
18	Production	\$ 867,922	\$ 871,341	\$ (3,419)
19	Transmission	\$ 145,282	\$ 145,297	\$ (16)
20	Distribution	\$ 309,041	\$ 309,041	\$ -
21	General & Intangible	\$ 95,774	\$ 96,275	\$ (501)
22	Nuclear Decommissioning Expense	\$ 4,338	\$ 4,338	\$ -
23	Amortization of Investment Tax Credits	\$ (8,818)	\$ (8,846)	\$ 28
24	Amortization of Obsolete Inventory	\$ 14,837	\$ 14,837	\$ -
25	Amortization of State Tax Reform Refund	\$ (1,231)	\$ (1,231)	\$ -
26	Amortization of Environmental CWIP	\$ 7,268	\$ 7,268	\$ -
27	Amortization of Retired Units' Net Book Value	\$ 67,049	\$ 67,049	\$ -
28	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ 4,256	\$ -
29	Amortization of Future Nuclear	\$ 16,262	\$ 16,262	\$ -
30	Total Depreciation and Amortization	<u>\$ 1,521,980</u>	<u>\$ 1,525,888</u>	<u>\$ (3,907)</u>
31	Taxes Other Than Income Taxes	\$ 284,411	\$ 284,628	\$ (216)
32	Income Taxes	<u>\$ (50,602)</u>	<u>\$ (49,413)</u>	<u>\$ (1,189)</u>
33	Total Expenses	<u>\$ 6,373,893</u>	<u>\$ 6,376,559</u>	<u>\$ (2,666)</u>
34	Operating Income	\$ 1,229,826	\$ 1,235,842	\$ (6,016)
35	Interest on Customer Deposits	<u>\$ (6,552)</u>	<u>\$ (6,552)</u>	<u>\$ -</u>
36	Retail Earnings Available For Return	<u>\$ 1,223,275</u>	<u>\$ 1,229,291</u>	<u>\$ (6,016)</u>

Notes and Source

Col. A: Amounts from Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 8

Col. B: Amounts from as-filed Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company), page 8

Georgia Power Company  
Company Errata - Operating Income Adjustments  
Retail Electric Amounts

Staff Exhibit (RS/RT-2)  
Schedule E-2  
Page 4 of 4

Calendar 2022  
(Thousands of Dollars)

Line No.	Description	Retail Adjusted Operating Income Per Errata (A)	As-Filed Retail Operating Income (B)	Adjustment (C)
<b>Operating Revenues</b>				
1	Electric Retail Revenues	\$ 7,548,972	\$ 7,559,183	\$ (10,211)
2	Other Operating Revenues	\$ 210,689	\$ 212,685	\$ (1,995)
3	Total Operating Revenues	<u>\$ 7,759,662</u>	<u>\$ 7,771,868</u>	<u>\$ (12,206)</u>
<b>Operating Expenses</b>				
4	Generation - Fixed	\$ 566,489	\$ 559,963	\$ 6,527
5	Generation - Fuel & Variable O&M	\$ 1,756,249	\$ 1,756,249	\$ -
6	Affiliated Purchased Power-Non-Fuel	\$ 130,315	\$ 130,315	\$ -
7	Affiliated Purchased Power-Fuel	\$ 404,695	\$ 404,695	\$ -
8	Non-Affiliated Purchased Power-Non-Fuel	\$ 155,206	\$ 155,206	\$ -
9	Non-Affiliated Purchased Power-Fuel	\$ 453,811	\$ 453,811	\$ -
10	System Control & Load Dispatching	\$ 36,029	\$ 36,029	\$ -
11	Transmission	\$ 128,102	\$ 128,102	\$ -
12	Distribution	\$ 289,039	\$ 289,039	\$ -
13	Customer Accounting	\$ 163,584	\$ 163,584	\$ -
14	Customer Assistance	\$ 119,153	\$ 122,732	\$ (3,579)
15	Energy Services	\$ 51,037	\$ 51,037	\$ -
16	Administrative & General	\$ 486,877	\$ 486,966	\$ (88)
17	Total Operations & Maintenance	<u>\$ 4,740,586</u>	<u>\$ 4,737,728</u>	<u>\$ 2,859</u>
<b>Depreciation and Amortization</b>				
18	Production	\$ 1,096,157	\$ 1,102,549	\$ (6,392)
19	Transmission	\$ 151,620	\$ 151,324	\$ 296
20	Distribution	\$ 333,581	\$ 333,581	\$ -
21	General & Intangible	\$ 104,230	\$ 104,784	\$ (555)
22	Nuclear Decommissioning Expense	\$ 4,338	\$ 4,338	\$ -
23	Amortization of Investment Tax Credits	\$ (11,186)	\$ (11,214)	\$ 28
24	Amortization of Obsolete Inventory	\$ 14,837	\$ 14,837	\$ -
25	Amortization of State Tax Reform Refund	\$ (1,231)	\$ (1,231)	\$ -
26	Amortization of Environmental CWIP	\$ 7,268	\$ 7,268	\$ -
27	Amortization of Retired Units' Net Book Value	\$ 67,052	\$ 67,052	\$ -
28	Amortization of Deferred Healthcare Costs	\$ 4,256	\$ 4,256	\$ -
29	Amortization of Future Nuclear	\$ 16,262	\$ 16,262	\$ -
30	Total Depreciation and Amortization	<u>\$ 1,787,184</u>	<u>\$ 1,793,806</u>	<u>\$ (6,622)</u>
31	Taxes Other Than Income Taxes	\$ 294,860	\$ 296,118	\$ (1,258)
32	Income Taxes	<u>\$ (87,193)</u>	<u>\$ (86,547)</u>	<u>\$ (647)</u>
33	Total Expenses	<u>\$ 6,735,437</u>	<u>\$ 6,741,106</u>	<u>\$ (5,669)</u>
34	Operating Income	\$ 1,024,225	\$ 1,030,762	\$ (6,537)
35	Interest on Customer Deposits	<u>\$ (6,697)</u>	<u>\$ (6,697)</u>	<u>\$ -</u>
36	Retail Earnings Available For Return	<u>\$ 1,017,527</u>	<u>\$ 1,024,065</u>	<u>\$ (6,537)</u>

Notes and Source

Col. A: Amounts from Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company Errata), page 10  
Col. B: Amounts from as-filed Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company), page 10

Line No.	Description	Composite Income Tax Rate	Forecasted Test Year Ending 7/31/2020 (A)	Calendar 2020 (B)	Calendar 2021 (C)	Calendar 2022 (D)	Reference
1	Adjustment to Reflect Interest Credits on Minimum Bank Balances		\$ (275)	\$ (275)	\$ (275)	\$ (275)	A
2	Jurisdictional Factor		98.75%	98.75%	98.75%	98.75%	
3	Retail Jurisdictional Adjustment to Reflect Interest Credits on Minimum Bank Balances		<u>\$ (272)</u>	<u>\$ (272)</u>	<u>\$ (272)</u>	<u>\$ (272)</u>	
4	Adjustment to Pre-Tax Operating Income		\$ 272	\$ 272	\$ 272	\$ 272	
5	Adjustment to Income Tax Expense	25.296%	<u>\$ (69)</u>	<u>\$ (69)</u>	<u>\$ (69)</u>	<u>\$ (69)</u>	
6	Impact on After-Tax Operating Income		<u>\$ 203</u>	<u>\$ 203</u>	<u>\$ 203</u>	<u>\$ 203</u>	

Notes and Source

A: Amount from the response to STF-L&A-11-19

Total O&M Expense allocator per Exhibit \_\_ (LJV-1), page 2, line 33:

7	Retail Service O&M Expense	\$ 4,362,948
8	Total Electric System O&M Expense	<u>\$ 4,418,196</u>
9	Retail Allocator	<u>98.75%</u>

Line No.	Description	FERC Account	Composite Income Tax Rate	Forecasted Test Year Ending 7/31/2020 (A)	Calendar 2020 (B)	Calendar 2021 (C)	Calendar 2022 (D)	Reference
<b>Rate Base</b>								
1	Plant-in-Service	101		\$ (4,094)	\$ (4,933)	\$ (6,933)	\$ (8,933)	
2	Accumulated Depreciation	108		\$ 291	\$ 342	\$ 505	\$ 721	
3	Materials and Supplies	154		\$ (24)	\$ (24)	\$ (24)	\$ (24)	
4	Accumulated Deferred Income Taxes	282		\$ 639	\$ 713	\$ 949	\$ 1,243	
5	Net Rate Base			<u>\$ (3,188)</u>	<u>\$ (3,902)</u>	<u>\$ (5,503)</u>	<u>\$ (6,993)</u>	
<b>Operating Income</b>								
6	Revenue	456		\$ (108)	\$ (115)	\$ (120)	\$ (123)	
7	Jurisdictional Factor			98.75%	98.75%	98.75%	98.75%	(1)
8	Retail Jurisdictional Adjustment to Remove Revenue Related to EV Charging Facilities			<u>\$ (107)</u>	<u>\$ (114)</u>	<u>\$ (118)</u>	<u>\$ (121)</u>	
9	O&M Expenses	908		\$ (325)	\$ (334)	\$ (342)	\$ (351)	
10	Jurisdictional Factor			98.75%	98.75%	98.75%	98.75%	(1)
11	Retail Jurisdictional Adjustment to Remove O&M Expense Related to EV Charging Facilities			<u>\$ (321)</u>	<u>\$ (330)</u>	<u>\$ (338)</u>	<u>\$ (347)</u>	
12	Depreciation Expense	403		\$ (88)	\$ (135)	\$ (189)	\$ (243)	
13	Jurisdictional Factor			98.75%	98.75%	98.75%	98.75%	(1)
14	Retail Jurisdictional Adjustment to Depreciation Expense Related to EV Charging Facilities			<u>\$ (87)</u>	<u>\$ (133)</u>	<u>\$ (187)</u>	<u>\$ (240)</u>	
15	Adjustment to Pre-Tax Operating Income			\$ 301	\$ 349	\$ 407	\$ 466	
16	Adjustment to Income Tax Expense		25.296%	\$ (76)	\$ (88)	\$ (103)	\$ (118)	
17	Impact on After-Tax Operating Income			<u>\$ 225</u>	<u>\$ 261</u>	<u>\$ 304</u>	<u>\$ 348</u>	

Notes and Source

Cols. A-D: Amounts from the response to STF-L&A-1-129

(1)	Total O&M Expense allocator per Exhibit (LJV-1), page 2, line 33:							
18							\$ 4,362,948	
19							\$ 4,418,196	
20							<u>98.75%</u>	

Retail Service O&M Expense  
Total Electric System O&M Expense  
Retail Allocator

Georgia Power Company  
Cash Working Capital  
Retail Electric Amounts  
Test Year Ended July 31, 2020  
(Thousands of Dollars)

Exhibit (RS/RT-2)  
Schedule E-5  
Page 1 of 4

Line No.	Description	Retail Cash Operating Expense Adjustment (A)	Cash Operating Expense Per Day (B)	Lag/ (Lead) Days (C)	Net Cash Expense Lag Days (D)	Adjustment to Cash Working Capital Retail Electric (E)
1	Operating Revenues					
				37.1		
2	Cash Operating Expenses:					
3	Fuels Other Than Nuclear	\$ -	-	(27.2)	9.9	\$ -
4	Nuclear Decommissioning	\$ -	-	(252.0)	(214.9)	\$ -
	Purchased Power:					
5	Purchases-Affiliated	\$ -	-	(27.7)	9.4	\$ -
6	Purchases-Non-Affiliated	\$ -	-	(28.6)	8.5	\$ -
7	Other Operating and Maintenance Expenses	\$ (24,922)	(68)	(30.3)	6.8	\$ (463)
8	Taxes Other Than Income Taxes	\$ (4,146)	(11)	(136.7)	(99.6)	\$ 1,132
9	Current Federal and State Income Taxes	\$ (2,067)	(6)	(37.5)	(0.4)	\$ 2
10	Interest Expense-Long Term Debt	\$ 34,457	94	(82.0)	(44.9)	\$ (4,241)
11	Total Cash Operating Expense Adjustments	<u>\$ 3,322</u>	<u>9</u>			
12	Adjustment to Cash Working Capital (Retail Electric)					<u>\$ (3,570)</u>
13	Adjustment to Cash Working Capital (Retail Electric) Rounded					<u>\$ (3,600)</u>

Notes and Source

Calculation applies Net Expense Lag to Staff Adjustments to Retail Electric Cash Operating Expenses to Derive CWC Adjustment Impacts  
Revenue and Expense lags are from Company Exhibit (DPP/SPA/MBR-2), pages 28 and 36.



Line No.	Description	Retail Cash Operating Expense Adjustment (A)	Cash Operating Expense Per Day (B)	Lag/ (Lead) Days (C)	Net Cash Expense Lag Days (D)	Adjustment to Cash Working Capital Retail Electric (E)
1	Operating Revenues					
	Cash Operating Expenses:					
2	Fuels Other Than Nuclear		\$ -	(27.2)	9.9	\$ -
3	Nuclear Decommissioning		\$ -	(252.0)	(214.9)	\$ -
	Purchased Power:					
4	Purchases-Affiliated		\$ -	(32.6)	4.4	\$ -
5	Purchases-Non-Affiliated		\$ -	(35.2)	1.9	\$ -
6	Other Operating and Maintenance Expenses	\$ (22,762)	(62)	(21.7)	15.4	\$ (959)
7	Taxes Other Than Income Taxes	\$ (4,199)	(12)	(165.5)	(128.4)	\$ 1,478
8	Current Federal and State Income Taxes	\$ (1,981)	(5)	(38.0)	(0.9)	\$ 5
9	Interest Expense-Long Term Debt	\$ 31,635	87	(79.4)	(42.4)	\$ (3,671)
10	Total Cash Operating Expense Adjustments	<u>\$ 2,693</u>	<u>7</u>			
11	Adjustment to Cash Working Capital (Retail Electric)					<u>\$ (3,148)</u>
12	Adjustment to Cash Working Capital (Retail Electric) Rounded					<u>\$ (3,100)</u>

Notes and Source

Calculation applies Net Expense Lag to Staff Adjustments to Retail Electric Cash Operating Expenses to Derive CWC Adjustment Impacts Revenue and Expense lags are from Company Exhibit (LIP/ELS-2), pages 28 and 37 of 37.

Line No.	Description	Retail Cash Operating Expense Adjustment (A)	Cash Operating Expense Per Day (B)	Lag/ (Lead) Days (C)	Net Cash Expense Lag Days (D)	Adjustment to Cash Working Capital Retail Electric (E)
1	Operating Revenues			37.1		
	Cash Operating Expenses:					
2	Fuels Other Than Nuclear		\$ -	(27.2)	9.9	\$ -
3	Nuclear Decommissioning		\$ -	(252.0)	(214.9)	\$ -
	Purchased Power:					
4	Purchases-Affiliated		\$ -	(32.6)	4.4	\$ -
5	Purchases-Non-Affiliated		\$ -	(35.2)	1.9	\$ -
6	Other Operating and Maintenance Expenses	\$ (25,938)	(71)	(21.7)	15.4	\$ (1,093)
7	Taxes Other Than Income Taxes	\$ (4,420)	(12)	(165.5)	(128.4)	\$ 1,556
8	Current Federal and State Income Taxes	\$ 2,464	7	(38.0)	(0.9)	\$ (6)
9	Interest Expense-Long Term Debt	\$ 18,414	50	(79.4)	(42.4)	\$ (2,137)
10	Total Cash Operating Expense Adjustments	<u>\$ (9,480)</u>	<u>\$ (26)</u>			
11	Adjustment to Cash Working Capital (Retail Electric)					<u>\$ (1,680)</u>
12	Adjustment to Cash Working Capital (Retail Electric) Rounded					<u>\$ (1,700)</u>

Notes and Source

Calculation applies Net Expense Lag to Staff Adjustments to Retail Electric Cash Operating Expenses to Derive CWC Adjustment Impacts Revenue and Expense lags are from Company Exhibit (LIP/ELS-2), pages 28 and 37 of 37.

Line No.	Description	Retail Cash Operating Expense Adjustment (A)	Cash Operating Expense Per Day (B)	Lag/ (Lead) Days (C)	Net Cash Expense Lag Days (D)	Adjustment to Cash Working Capital Retail Electric (E)
1	Operating Revenues					
	Cash Operating Expenses:			37.1		
2	Fuels Other Than Nuclear		\$ -	(27.2)	9.9	\$ -
3	Nuclear Decommissioning		\$ -	(252.0)	(214.9)	\$ -
	Purchased Power:					
4	Purchases-Affiliated		\$ -	(32.6)	4.4	\$ -
5	Purchases-Non-Affiliated		\$ -	(35.2)	1.9	\$ -
6	Other Operating and Maintenance Expenses		(74)	(21.7)	15.4	(1,141)
7	Taxes Other Than Income Taxes	\$ (27,097)	(15)	(165.5)	(128.4)	\$ 1,959
8	Current Federal and State Income Taxes	\$ (5,565)	20	(38.0)	(0.9)	\$ (19)
9	Interest Expense-Long Term Debt	\$ 7,458	\$ 6	(79.4)	(42.4)	\$ (271)
10	Total Cash Operating Expense Adjustments	<u>\$ 2,339</u>	<u>\$ (63)</u>			
		<u>\$ (22,865)</u>				
11	Adjustment to Cash Working Capital (Retail Electric)					<u>\$ 527</u>
12	Adjustment to Cash Working Capital (Retail Electric) Rounded					<u>\$ 500</u>

Notes and Source

Calculation applies Net Expense Lag to Staff Adjustments to Retail Electric Cash Operating Expenses to Derive CWC Adjustment Impacts Revenue and Expense lags are from Company Exhibit (LIP/ELS-2), pages 28 and 37 of 37.

Line No.	Description	Composite Income Tax Rate	Forecasted Test Year Ending 7/31/2020 (A)	Calendar 2020 (B)	Calendar 2021 (C)	Calendar 2022 (D)	Reference
1	Remove GPC Directly Incurred Expenses for Executive Personal Financial Planning - FERC 926		\$ (164)	\$ (164)	\$ (164)	\$ (164)	(1)
2	Remove SCS Allocated Expenses for Executive Personal Financial Planning - FERC 926		\$ (180)	\$ (180)	\$ (180)	\$ (180)	(1)
3	Total GPC Directly Incurred and SCS Allocated Expenses for Executive Financial Planning		\$ (344)	\$ (344)	\$ (344)	\$ (344)	
4	Jurisdictional Factor		98.75%	98.75%	98.75%	98.75%	(2)
5	Jurisdictional Adjustment to Remove GPC Directly Incurred and SCS Allocated Expenses for Executive Personal Financial Planning		\$ (340)	\$ (340)	\$ (340)	\$ (340)	
6	Remove SNOC Allocated Expenses for Executive Personal Financial Planning - FERC 524		\$ (70)	\$ (70)	\$ (70)	\$ (70)	(1)
7	Jurisdictional Factor		98.75%	98.75%	98.75%	98.75%	(2)
8	Jurisdictional Adjustment to Remove SNOC Allocated Expenses for Executive Personal Financial Planning		\$ (69)	\$ (69)	\$ (69)	\$ (69)	
9	Adjustment to Pre-Tax Operating Income		\$ 409	\$ 409	\$ 409	\$ 409	
10	Adjustment to Income Tax Expense	25.296%	\$ (103)	\$ (103)	\$ (103)	\$ (103)	
11	Impact on After-Tax Operating Income		\$ 306	\$ 306	\$ 306	\$ 306	

Notes and Source

(1) STF-L&A-1-60

(2) Total O&M Expense allocator per Exhibit \_\_ (LJV-1), page 2, line 33:

Retail Service O&M Expense	\$ 4,362,948
Total Electric System O&M Expense	\$ 4,418,196
Retail Allocator	98.75%

Line No.	Description	Composite Income Tax Rate	Forecasted Test Year Ending 7/31/2020 (A)	Calendar 2020 (B)	Calendar 2021 (C)	Calendar 2022 (D)	Reference
1	Adjustment to Property Tax Expense to Reflect Average True-Ups		\$ (2,604)	\$ (2,604)	\$ (2,604)	\$ (2,604)	(1)
2	Jurisdictional Factor		98.89%	98.89%	98.89%	98.89%	(2)
3	Retail Jurisdictional Adjustment to Property Tax Expense to Reflect Average True-Ups		\$ (2,575)	\$ (2,575)	\$ (2,575)	\$ (2,575)	
4	Adjustment to Pre-Tax Operating Income		\$ 2,575	\$ 2,575	\$ 2,575	\$ 2,575	
5	Adjustment to Income Tax Expense	25.296%	\$ (651)	\$ (651)	\$ (651)	\$ (651)	
6	Impact on After-Tax Operating Income		\$ 1,924	\$ 1,924	\$ 1,924	\$ 1,924	

Notes and Source

(1) Staff's adjustment to Property Tax Expense is calculated from data provided in STF-RCS-1-35 (Docket No. 36989) and STF-L&A-1-47 (original and supplemental) as shown below:

Property Tax Year	Amount
2002	\$ (3,170,903)
2003	\$ 1,138,841
2004	\$ (1,622,349)
2005	\$ (2,683,199)
2006	\$ (5,000,000)
2007	\$ (10,325,497)
2008	\$ (8,481,463)
2009	\$ (105,638)
2010	\$ (56,679)
2011	\$ (347,671)
2012	\$ (1,796,773)
2013	\$ (5,057,285)
2014	\$ (4,012,153)
2015	\$ 320,798
2016	\$ (533,293)
2017	\$ (4,868,985)
2018	\$ 2,331,430
Average	\$ (2,604,166)

(2)	Total Taxes Other Than Income Expense allocator per Exhibit (LJV-1), page 2 of 74	\$ 268,630
25	Retail Service Taxes Other Than Income	\$ 271,653
26	Total Electric System Taxes Other Than Income	98.89%
27	Retail Allocator	

Georgia Power Company  
Interest Synchronization  
Retail Electric Amounts  
Test Year Ended July 31, 2020  
(Thousands of Dollars)

Exhibit \_\_ (RS/RT-2)  
Schedule E-8  
Page 1 of 4

Line No.	Description	Per Company Amount - Retail (A)	Per Staff Amount (B)	Reference
1	Adjusted Retail Rate Base	\$ 20,097,349	\$ 20,063,489	Schedule B , page 1
2	Weighted Cost of Debt	1.82%	1.99%	Schedule D , page 1
3	Synchronized Interest Deduction	\$ 365,669	\$ 400,126	L1 x L2
4	Increase (Decrease) in Deductible Interest		\$ 34,457	L3, B-A
5	Composite Income Tax Rate		25.296%	Schedule A-1. page 1
6	Increase (Decrease) to Income Tax Expense		\$ (8,716)	

Line No.	Description	Per Company Amount (A)	Per Staff Amount (B)	Reference
1	Adjusted Retail Rate Base	\$ 20,712,373	\$ 20,662,417	Schedule B , page 2
2	Weighted Cost of Debt	1.88%	2.03%	Schedule D , page 2
3	Synchronized Interest Deduction	\$ 388,535	\$ 420,170	L1 x L2
4	Increase (Decrease) in Deductible Interest		\$ 31,635	L3, B-A
5	Composite Income Tax Rate		25.296%	Schedule A-1, page 2
6	Increase (Decrease) to Income Tax Expense		<u>\$ (8,002)</u>	

Line No.	Description	Per Company Amount (A)	Per Staff Amount (B)	Reference
1	Adjusted Retail Rate Base	\$ 21,797,091	\$ 21,672,609	Schedule B , page 3
2	Weighted Cost of Debt	1.97%	2.06%	Schedule D , page 3
3	Synchronized Interest Deduction	\$ 428,670	\$ 447,084	L1 x L2
4	Increase (Decrease) in Deductible Interest		\$ 18,414	L3, B-A
5	Composite Income Tax Rate		25.296%	Schedule A-1, page 2
6	Increase (Decrease) to Income Tax Expense		<u>\$ (4,658)</u>	



Georgia Power Company  
Interest Synchronization  
Retail Electric Amounts  
Calendar Year 2022  
(Thousands of Dollars)

Exhibit \_\_ (RS/RT-2)  
Schedule E-8  
Page 4 of 4

Line No.	Description	Per Company Amount (A)	Per Staff Amount (B)	Reference
1	Adjusted Retail Rate Base	\$ 22,848,345	\$ 22,628,881	Schedule B , page 4
2	Weighted Cost of Debt	2.02%	2.05%	Schedule D , page 4
3	Synchronized Interest Deduction	\$ 462,255	\$ 464,594	L1 x L2
4	Increase (Decrease) in Deductible Interest		\$ 2,339	L3, B-A
5	Composite Income Tax Rate		25.296%	Schedule A-1, page 2
6	Increase (Decrease) to Income Tax Expense		\$ (592)	

Georgia Power Company  
Stock-Based Compensation  
Retail Electric Amounts  
Test Year Ending July 31, 2020  
(Thousand of Dollars)

Exhibit (RS/RT-2)

Schedule E-9  
Page 1 of 4

Line No.	Description	Composite Income Tax Rate (A)	Total Amount (B)	O&M Expense Ratio (C)	Staff Adjustment to O&M Expense (D)
<b>I. Performance Share Program</b>					
1	Georgia Power Directly Incurred		\$ (8,045)	89.58%	\$ (7,206)
2	SCS - Allocated to Georgia Power		\$ (7,027)	68.87%	\$ (4,839)
3	SNC - Allocated to Georgia Power		\$ (3,129)	67.96%	\$ (2,126)
4	Total PSP Expense		\$ (18,200)		\$ (14,171)
<b>II. Restricted Stock Units</b>					
5	Georgia Power Directly Incurred		\$ (3,003)	89.48%	\$ (2,687)
6	SCS - Allocated to Georgia Power		\$ (2,651)	69.03%	\$ (1,830)
7	SNC - Allocated to Georgia Power		\$ (1,257)	63.19%	\$ (794)
8	Total RSU Expense		\$ (6,911)		\$ (5,311)
9	Total Stock-Based Compensation Expense				\$ (19,482)
10	Retail Allocator				100.00%
11	Adjustment to Remove Retail Stock-Based Compensation Expense				\$ (19,482)
12	Adjustment to Pre-Tax Operating Income				\$ 19,482
13	Adjustment to Income Tax Expense	25.296%			\$ (4,928)
14	Impact on After-Tax Operating Income				\$ 14,554

Notes and Source

Col. B: Amounts from the response to STF-L&A-1-82

Col. C: O&M expense ratios derived from the responses to STF-L&A-1-83 and STF-L&A-11-30

Georgia Power Company  
Stock-Based Compensation  
Retail Electric Amounts  
Calendar 2020  
(Thousand of Dollars)

Exhibit (RS/RT-2)  
Schedule E-9  
Page 2 of 4

Line No.	Description	Composite Income Tax Rate (A)	Total Amount (B)	O&M Expense Ratio (C)	Staff Adjustment to O&M Expense (D)
<b>I. Performance Share Program</b>					
1	Georgia Power Directly Incurred		\$ (8,157)	89.58%	\$ (7,307)
2	SCS - Allocated to Georgia Power		\$ (6,958)	69.49%	\$ (4,835)
3	SNC - Allocated to Georgia Power		\$ (2,995)	67.96%	\$ (2,036)
4	Total PSP Expense		\$ (18,109)		\$ (14,178)
<b>II. Restricted Stock Units</b>					
5	Georgia Power Directly Incurred		\$ (3,031)	89.48%	\$ (2,713)
6	SCS - Allocated to Georgia Power		\$ (2,553)	68.81%	\$ (1,757)
7	SNC - Allocated to Georgia Power		\$ (1,193)	63.19%	\$ (754)
8	Total Stock Option Expense		\$ (6,777)		\$ (5,224)
9	Total Stock-Based Compensation Expense				\$ (19,402)
10	Retail Allocator				100.00%
11	Adjustment to Remove Retail Stock-Based Compensation Expense				\$ (19,402)
12	Adjustment to Pre-Tax Operating Income				\$ 19,402
13	Adjustment to Income Tax Expense	25.296%			\$ (4,908)
14	Impact on After-Tax Operating Income				\$ 14,494

Notes and Source

Col. B: Amounts from the response to STF-L&A-1-82

Col. C: O&M expense ratios derived from the responses to STF-L&A-1-83 and STF-L&A-11-30

Georgia Power Company  
Stock-Based Compensation  
Retail Electric Amounts  
Calendar 2021  
(Thousand of Dollars)

Exhibit (RS/RT-2)  
Schedule E-9  
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Line No.	Description	Composite Income Tax Rate (A)	Total Amount (B)	O&M Expense Ratio (C)	Staff Adjustment to O&M Expense (D)
<b>I. Performance Share Program</b>					
1	Georgia Power Directly Incurred		\$ (8,792)	89.58%	\$ (7,876)
2	SCS - Allocated to Georgia Power		\$ (8,662)	67.44%	\$ (5,842)
3	SNC - Allocated to Georgia Power		\$ (3,114)	69.49%	\$ (2,164)
4	Total PSP Expense		\$ (20,568)		\$ (15,882)
<b>II. Restricted Stock Units</b>					
5	Georgia Power Directly Incurred		\$ (3,152)	89.48%	\$ (2,820)
6	SCS - Allocated to Georgia Power		\$ (2,666)	69.27%	\$ (1,847)
7	SNC - Allocated to Georgia Power		\$ (1,162)	63.19%	\$ (734)
8	Total Stock Option Expense		\$ (6,980)		\$ (5,401)
9	Total Stock-Based Compensation Expense				\$ (21,283)
10	Retail Allocator				100.00%
11	Adjustment to Remove Retail Stock-Based Compensation Expense				\$ (21,283)
12	Adjustment to Pre-Tax Operating Income				\$ 21,283
13	Adjustment to Income Tax Expense	25.296%			\$ (5,384)
14	Impact on After-Tax Operating Income				\$ 15,899

Notes and Source

Col. B: Amounts from the response to STF-L&A-1-82

Col. C: O&M expense ratios derived from the responses to STF-L&A-1-83 and STF-L&A-11-30

Georgia Power Company  
Stock-Based Compensation  
Retail Electric Amounts  
Calendar 2022  
(Thousand of Dollars)

Exhibit (RS/RT-2)  
Schedule E-9  
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Line No.	Description	Composite Income Tax Rate (A)	Total Amount (B)	O&M Expense Ratio (C)	Staff Adjustment to O&M Expense (D)
<b>I. Performance Share Program</b>					
1	Georgia Power Directly Incurred		\$ (9,056)	89.58%	\$ (8,112)
2	SCS - Allocated to Georgia Power		\$ (8,861)	67.63%	\$ (5,992)
3	SNC - Allocated to Georgia Power		\$ (3,203)	88.41%	\$ (2,832)
4	Total PSP Expense		\$ (21,120)		\$ (16,936)
<b>II. Restricted Stock Units</b>					
5	Georgia Power Directly Incurred		\$ (3,214)	89.48%	\$ (2,876)
6	SCS - Allocated to Georgia Power		\$ (2,726)	68.77%	\$ (1,875)
7	SNC - Allocated to Georgia Power		\$ (1,172)	81.59%	\$ (957)
8	Total Stock Option Expense		\$ (7,113)		\$ (5,708)
9	Total Stock-Based Compensation Expense				\$ (22,644)
10	Retail Allocator				100.00%
11	Adjustment to Remove Retail Stock-Based Compensation Expense				\$ (22,644)
12	Adjustment to Pre-Tax Operating Income				\$ 22,644
13	Adjustment to Income Tax Expense	25.296%			\$ (5,728)
14	Impact on After-Tax Operating Income				\$ 16,916

Notes and Source

Col. B: Amounts from the response to STF-L&A-1-82

Col. C: O&M expense ratios derived from the responses to STF-L&A-1-83 and STF-L&A-11-30

Exhibit (RS/RT-2)  
Schedule E-10  
Page 1 of 1

Georgia Power Company  
Payroll Tax Expense  
Retail Electric Amounts

(Thousands of Dollars)

Line No.	Description	7/31/2020 (A)	12/31/2020 (B)	12/31/2021 (C)	12/31/2022 (F)	Reference
<b>FICA Taxes</b>						
1	Adjustment to Remove Retail Stock-Based Compensation Expense	\$ (19,482)	\$ (19,402)	\$ (21,283)	\$ (22,644)	A
2	FICA Tax Rate*	6.20%	6.20%	6.20%	6.20%	
3	Adjustment to FICA Portion of Payroll Tax Expense	<u>\$ (1,208)</u>	<u>\$ (1,203)</u>	<u>\$ (1,320)</u>	<u>\$ (1,404)</u>	L1 x L2
<b>Medicare</b>						
4	Adjustment to Remove Retail Stock-Based Compensation Expense	\$ (19,482)	\$ (19,402)	\$ (21,283)	\$ (22,644)	A
5	Medicare Tax Rate	1.45%	1.45%	1.45%	1.45%	
6	Adjustment to Medicare Portion of Payroll Tax Expense	<u>\$ (282)</u>	<u>\$ (281)</u>	<u>\$ (309)</u>	<u>\$ (328)</u>	L4 x L5
7	Total Adjustment to Payroll Tax Expense	<u>\$ (1,490)</u>	<u>\$ (1,484)</u>	<u>\$ (1,629)</u>	<u>\$ (1,732)</u>	L3 + L6

Notes and Source

A: See Schedule E-9

\* The maximum amount of wages in 2018 subject to the 6.20% Social Security tax was \$128,400 and is \$132,900 for 2019. The maximum amount of wages in 2020 subject to the 6.20% Social Security tax is projected to be \$136,800. To the extent that the salaries of certain individuals included in the adjustments listed are above the projected FICA tax threshold of \$136,800 for 2020, this adjustment to Payroll Tax expense could be modified accordingly.

Line No.	Description	Composite Income Tax Rate	Forecasted Test Year				Reference
			7/31/2020 (A)	2020 (B)	2021 (C)	2022 (D)	
1	Projected Uncollectibles Expense Per Company		\$ 13,445	\$ 14,003	\$ 14,003	\$ 14,004	
2	Staff Recommended Uncollectibles Expense		\$ 12,000	\$ 12,000	\$ 12,000	\$ 12,000	
3	Staff Adjustment to Uncollectibles Expense		\$ (1,445)	\$ (2,003)	\$ (2,003)	\$ (2,004)	
4	Jurisdictional Factor		98.75%	98.75%	98.75%	98.75%	(1)
5	Jurisdictional Adjustment to Uncollectibles Expense		<u>\$ (1,427)</u>	<u>\$ (1,978)</u>	<u>\$ (1,978)</u>	<u>\$ (1,979)</u>	
6	Adjustment to Pre-Tax Operating Income		\$ 1,427	\$ 1,978	\$ 1,978	\$ 1,979	
7	Adjustment to Income Tax Expense	25.296%	<u>\$ (361)</u>	<u>\$ (500)</u>	<u>\$ (500)</u>	<u>\$ (501)</u>	
8	Impact on After-Tax Operating Income		<u>\$ 1,066</u>	<u>\$ 1,478</u>	<u>\$ 1,478</u>	<u>\$ 1,478</u>	

Notes and Source

Col. A, line 1: Amount from the response to STF-PIA-10-3  
Col. B, line 1: Amount from the response to STF-PIA-10-4  
Col. C, line 1: Amount from the response to STF-PIA-10-5  
Col. D, line 1: Amount from the response to STF-PIA-10-6

Cols. A-D, line 2: Staff testimony

(1) Total O&M Expense allocator per Exhibit \_\_ (LJV-1), page 2, line 33:

9	Retail Service O&M Expense	\$ 4,362,948
10	Total Electric System O&M Expense	<u>\$ 4,418,196</u>
11	Retail Allocator	<u>98.75%</u>

Georgia Power Company  
Storm Damage Accrual  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-12  
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Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Test Year Storm Damage Accrual Per Company (A)	Test Year Storm Damage Accrual Per Staff (B)	Staff Adjustment (C)	Reference
<b>Estimated Reserve Deficiency at 12/31/2019:</b>					
1	Actual Reserve Deficiency at 12/31/2018	\$ (415,786)	\$ (415,786)		
2	2019 Accrual	\$ 29,914	\$ 29,914		
3	Estimated 2019 Expenditures	\$ (63,528)	\$ (50,614)		
4	Estimated Reserve Deficiency at 12/31/2019	<u>\$ (449,400)</u>	<u>\$ (436,486)</u>	<u>\$ (12,914)</u>	
<b>Calculation of Proposed Storm Damage Accrual:</b>					
5	Projected Annual Expense	\$ 63,528	\$ 63,528	\$ -	
6	Reserve Deficiency Amortized over 3-Year Period	\$ 149,800	\$ 145,495	\$ (4,305)	L4 / 3
7	Proposed Accrual	<u>\$ 213,328</u>	<u>\$ 209,024</u>	<u>\$ (4,305)</u>	

#### Notes and Source

Col. A: Amounts from Company Exhibit \_\_ (DPP/SPA/MBR-5, Schedule 2). Estimated 2019 expenditures are calculated below:

	Projected Annual Expenditures Based on 10-Year Average:	Amount
8	2009	\$ 15,666
9	2010	7,681
10	2011	53,059
11	2012	13,580
12	2013	17,001
13	2014	90,943
14	2015	23,487
15	2016	144,469
16	2017	156,806
17	2018	<u>112,591</u>
18	10-Year Average	<u>\$ 63,528</u>
19	Company Projection for 2019	<u>\$ 63,528</u>
20	Company Projected Plan Year Storm Charges	<u>\$ 63,528</u>

Col. B: Staff recommended storm damage accrual calculated below using information from Attachment STF-L&A-1-39a

		Amount
21	Jan-19 Actual Charges	\$ (3,695)
22	Feb-19 Actual Charges	\$ 14,581
23	Mar-19 Actual Charges	\$ 3,443
24	Apr-19 Actual Charges	\$ 7,404
25	May-19 Actual Charges	\$ (4,593)
26	Jun-19 Actual Charges	\$ 1,710
27	Jul-19 Projected Charges	\$ 5,294
28	Aug-19 Projected Charges	\$ 5,294
29	Sep-19 Projected Charges	\$ 5,294
30	Oct-19 Projected Charges	\$ 5,294
31	Nov-19 Projected Charges	\$ 5,294
32	Dec-19 Projected Charges	\$ 5,294
33	Staff Recommended Annual Storm Charges	\$ 50,614



Georgia Power Company  
Storm Damage Accrual  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-12  
Page 2 of 4

Calendar Years 2020-2022  
(Thousands of Dollars)

Line No.	Description	Per Company (A)	Per Staff (B)	Staff Adjustment (C)	Reference
<b>Calendar 2020</b>					
1	Projected Annual Expense	\$ 63,528	\$ 63,528	\$ -	Page 1
2	Reserve Deficiency Amortized Over a 3-Year Period	<u>\$ 149,800</u>	<u>\$ 145,495</u>	<u>\$ (4,305)</u>	Page 1
3	Proposed Accrual	<u><u>\$ 213,328</u></u>	<u><u>\$ 209,024</u></u>	<u><u>\$ (4,305)</u></u>	
<b>Calendar 2021</b>					
4	Projected Annual Expense	\$ 63,528	\$ 63,528	\$ -	Page 1
5	Reserve Deficiency Amortized Over a 3-Year Period	<u>\$ 149,800</u>	<u>\$ 145,495</u>	<u>\$ (4,305)</u>	Page 1
6	Proposed Accrual	<u><u>\$ 213,328</u></u>	<u><u>\$ 209,024</u></u>	<u><u>\$ (4,305)</u></u>	
<b>Calendar 2022</b>					
7	Projected Annual Expense	\$ 63,528	\$ 63,528	\$ -	Page 1
8	Reserve Deficiency Amortized Over a 3-Year Period	<u>\$ 149,800</u>	<u>\$ 145,495</u>	<u>\$ (4,305)</u>	Page 1
9	Proposed Accrual	<u><u>\$ 213,328</u></u>	<u><u>\$ 209,024</u></u>	<u><u>\$ (4,305)</u></u>	

Georgia Power Company  
Storm Damage Accrual  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-12  
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Calendar Years 2020-2022  
(Thousands of Dollars)

Line No.	Description	Per Company (A)	Per Staff (B)	Staff Adjustment (C)	Reference
<b>Test Year Ending July 31, 2020</b>					
1	13-Month Average Ending Balance	\$ 419,281	\$ 407,139	\$ (12,141)	See below
2	Combined Federal and State Tax Rate			25.296%	
3	Staff Adjustment to ADIT			<u>\$ 3,071</u>	
4	Net Adjustment to Rate Base			<u>\$ (9,070)</u>	
<b>Calendar 2020</b>					
5	13-Month Average Ending Balance	\$ 374,500	\$ 363,738	\$ (10,762)	Page 4
6	Combined Federal and State Tax Rate			25.296%	
7	Staff Adjustment to ADIT			<u>\$ 2,722</u>	
8	Net Adjustment to Rate Base			<u>\$ (8,040)</u>	
<b>Calendar 2021</b>					
9	13-Month Average Ending Balance	\$ 224,700	\$ 218,243	\$ (6,457)	Page 4
10	Combined Federal and State Tax Rate			25.296%	
11	Staff Adjustment to ADIT			<u>\$ 1,633</u>	
12	Net Adjustment to Rate Base			<u>\$ (4,824)</u>	
<b>Calendar 2022</b>					
13	13-Month Average Ending Balance	\$ 74,900	\$ 72,748	\$ (2,152)	Page 4
14	Combined Federal and State Tax Rate			25.296%	
15	Staff Adjustment to ADIT			<u>\$ 544</u>	
16	Net Adjustment to Rate Base			<u>\$ (1,608)</u>	

Notes and Source

Per Company test year 13-month average regulatory asset from Attachment STF-L&A-1-39a and calculated below:

Per Company		Beginning Balance	Accrual	Charges	Ending Balance
Date					
17	Jan-19	\$ 415,786	\$ (2,493)	\$ 5,294	\$ 418,587
18	Feb-19	\$ 418,587	\$ (2,493)	\$ 5,294	\$ 421,388
19	Mar-19	\$ 421,388	\$ (2,493)	\$ 5,294	\$ 424,189
20	Apr-19	\$ 424,189	\$ (2,493)	\$ 5,294	\$ 426,990
21	May-19	\$ 426,990	\$ (2,493)	\$ 5,294	\$ 429,792
22	Jun-19	\$ 429,792	\$ (2,493)	\$ 5,294	\$ 432,593
23	Jul-19	\$ 432,593	\$ (2,493)	\$ 5,294	\$ 435,394
24	Aug-19	\$ 435,394	\$ (2,493)	\$ 5,294	\$ 438,195
25	Sep-19	\$ 438,195	\$ (2,493)	\$ 5,294	\$ 440,996
26	Oct-19	\$ 440,996	\$ (2,493)	\$ 5,294	\$ 443,798
27	Nov-19	\$ 443,798	\$ (2,493)	\$ 5,294	\$ 446,599
28	Dec-19	\$ 446,599	\$ (2,493)	\$ 5,294	\$ 449,400
29	Jan-20	\$ 449,400	\$ (17,777)	\$ 5,294	\$ 436,917
30	Feb-20	\$ 436,917	\$ (17,777)	\$ 5,294	\$ 424,433
31	Mar-20	\$ 424,433	\$ (17,777)	\$ 5,294	\$ 411,950
32	Apr-20	\$ 411,950	\$ (17,777)	\$ 5,294	\$ 399,467
33	May-20	\$ 399,467	\$ (17,777)	\$ 5,294	\$ 386,983
34	Jun-20	\$ 386,983	\$ (17,777)	\$ 5,294	\$ 374,500
35	Jul-20	\$ 374,500	\$ (17,777)	\$ 5,294	<u>\$ 362,017</u>
36	Per Company Test Year 13-Month Average Regulatory Asset				<u>\$ 419,281</u>
Per Staff		Beginning Balance	Accrual	Charges*	Ending Balance
Date					
37	Jan-19	\$ 415,786	\$ (2,493)	\$ (3,695)	\$ 409,598
38	Feb-19	\$ 409,598	\$ (2,493)	\$ 14,581	\$ 421,686
39	Mar-19	\$ 421,686	\$ (2,493)	\$ 3,443	\$ 422,636
40	Apr-19	\$ 422,636	\$ (2,493)	\$ 7,404	\$ 427,547
41	May-19	\$ 427,547	\$ (2,493)	\$ (4,593)	\$ 420,461
42	Jun-19	\$ 420,461	\$ (2,493)	\$ 1,710	\$ 419,679
43	Jul-19	\$ 419,679	\$ (2,493)	\$ 5,294	\$ 422,480
44	Aug-19	\$ 422,480	\$ (2,493)	\$ 5,294	\$ 425,281
45	Sep-19	\$ 425,281	\$ (2,493)	\$ 5,294	\$ 428,082
46	Oct-19	\$ 428,082	\$ (2,493)	\$ 5,294	\$ 430,884
47	Nov-19	\$ 430,884	\$ (2,493)	\$ 5,294	\$ 433,685
48	Dec-19	\$ 433,685	\$ (2,493)	\$ 5,294	\$ 436,486
49	Jan-20	\$ 436,486	\$ (17,419)	\$ 5,294	\$ 424,361
50	Feb-20	\$ 424,361	\$ (17,419)	\$ 5,294	\$ 412,237
51	Mar-20	\$ 412,237	\$ (17,419)	\$ 5,294	\$ 400,112
52	Apr-20	\$ 400,112	\$ (17,419)	\$ 5,294	\$ 387,987
53	May-20	\$ 387,987	\$ (17,419)	\$ 5,294	\$ 375,863
54	Jun-20	\$ 375,863	\$ (17,419)	\$ 5,294	\$ 363,738
55	Jul-20	\$ 363,738	\$ (17,419)	\$ 5,294	<u>\$ 351,614</u>
56	Per Staff Test Year 13-Month Average Regulatory Asset				<u>\$ 407,139</u>

\* Staff used actual storm charges for the period January through June 2019 per Attachment STF-L&A-1-39a

Georgia Power Company  
Storm Damage Accrual  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-2)  
Schedule E-12  
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Calendar Years 2020-2022  
(Thousands of Dollars)

Line No.	Per Company					Per Staff				
	Month	Beginning Balance	Accrual	Charges	Ending Balance	Month	Beginning Balance	Accrual	Charges	Ending Balance
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Dec-19				\$ 449,400	Dec-19				\$ 436,486
2	Jan-20	\$ 449,400	\$ (17,777)	\$ 5,294	\$ 436,917	Jan-20	\$ 436,486	\$ (17,419)	\$ 5,294	\$ 424,361
3	Feb-20	\$ 436,917	\$ (17,777)	\$ 5,294	\$ 424,433	Feb-20	\$ 424,361	\$ (17,419)	\$ 5,294	\$ 412,237
4	Mar-20	\$ 424,433	\$ (17,777)	\$ 5,294	\$ 411,950	Mar-20	\$ 412,237	\$ (17,419)	\$ 5,294	\$ 400,112
5	Apr-20	\$ 411,950	\$ (17,777)	\$ 5,294	\$ 399,467	Apr-20	\$ 400,112	\$ (17,419)	\$ 5,294	\$ 387,987
6	May-20	\$ 399,467	\$ (17,777)	\$ 5,294	\$ 386,983	May-20	\$ 387,987	\$ (17,419)	\$ 5,294	\$ 375,863
7	Jun-20	\$ 386,983	\$ (17,777)	\$ 5,294	\$ 374,500	Jun-20	\$ 375,863	\$ (17,419)	\$ 5,294	\$ 363,738
8	Jul-20	\$ 374,500	\$ (17,777)	\$ 5,294	\$ 362,017	Jul-20	\$ 363,738	\$ (17,419)	\$ 5,294	\$ 351,614
9	Aug-20	\$ 362,017	\$ (17,777)	\$ 5,294	\$ 349,533	Aug-20	\$ 351,614	\$ (17,419)	\$ 5,294	\$ 339,489
10	Sep-20	\$ 349,533	\$ (17,777)	\$ 5,294	\$ 337,050	Sep-20	\$ 339,489	\$ (17,419)	\$ 5,294	\$ 327,364
11	Oct-20	\$ 337,050	\$ (17,777)	\$ 5,294	\$ 324,567	Oct-20	\$ 327,364	\$ (17,419)	\$ 5,294	\$ 315,240
12	Nov-20	\$ 324,567	\$ (17,777)	\$ 5,294	\$ 312,083	Nov-20	\$ 315,240	\$ (17,419)	\$ 5,294	\$ 303,115
13	Dec-20	\$ 312,083	\$ (17,777)	\$ 5,294	\$ 299,600	Dec-20	\$ 303,115	\$ (17,419)	\$ 5,294	\$ 290,991
14	Jan-21	\$ 299,600	\$ (17,777)	\$ 5,294	\$ 287,117	Jan-21	\$ 290,991	\$ (17,419)	\$ 5,294	\$ 278,866
15	Feb-21	\$ 287,117	\$ (17,777)	\$ 5,294	\$ 274,633	Feb-21	\$ 278,866	\$ (17,419)	\$ 5,294	\$ 266,741
16	Mar-21	\$ 274,633	\$ (17,777)	\$ 5,294	\$ 262,150	Mar-21	\$ 266,741	\$ (17,419)	\$ 5,294	\$ 254,617
17	Apr-21	\$ 262,150	\$ (17,777)	\$ 5,294	\$ 249,667	Apr-21	\$ 254,617	\$ (17,419)	\$ 5,294	\$ 242,492
18	May-21	\$ 249,667	\$ (17,777)	\$ 5,294	\$ 237,183	May-21	\$ 242,492	\$ (17,419)	\$ 5,294	\$ 230,368
19	Jun-21	\$ 237,183	\$ (17,777)	\$ 5,294	\$ 224,700	Jun-21	\$ 230,368	\$ (17,419)	\$ 5,294	\$ 218,243
20	Jul-21	\$ 224,700	\$ (17,777)	\$ 5,294	\$ 212,217	Jul-21	\$ 218,243	\$ (17,419)	\$ 5,294	\$ 206,118
21	Aug-21	\$ 212,217	\$ (17,777)	\$ 5,294	\$ 199,733	Aug-21	\$ 206,118	\$ (17,419)	\$ 5,294	\$ 193,994
22	Sep-21	\$ 199,733	\$ (17,777)	\$ 5,294	\$ 187,250	Sep-21	\$ 193,994	\$ (17,419)	\$ 5,294	\$ 181,869
23	Oct-21	\$ 187,250	\$ (17,777)	\$ 5,294	\$ 174,767	Oct-21	\$ 181,869	\$ (17,419)	\$ 5,294	\$ 169,745
24	Nov-21	\$ 174,767	\$ (17,777)	\$ 5,294	\$ 162,283	Nov-21	\$ 169,745	\$ (17,419)	\$ 5,294	\$ 157,620
25	Dec-21	\$ 162,283	\$ (17,777)	\$ 5,294	\$ 149,800	Dec-21	\$ 157,620	\$ (17,419)	\$ 5,294	\$ 145,495
26	Jan-22	\$ 149,800	\$ (17,777)	\$ 5,294	\$ 137,317	Jan-22	\$ 145,495	\$ (17,419)	\$ 5,294	\$ 133,371
27	Feb-22	\$ 137,317	\$ (17,777)	\$ 5,294	\$ 124,833	Feb-22	\$ 133,371	\$ (17,419)	\$ 5,294	\$ 121,246
28	Mar-22	\$ 124,833	\$ (17,777)	\$ 5,294	\$ 112,350	Mar-22	\$ 121,246	\$ (17,419)	\$ 5,294	\$ 109,121
29	Apr-22	\$ 112,350	\$ (17,777)	\$ 5,294	\$ 99,867	Apr-22	\$ 109,121	\$ (17,419)	\$ 5,294	\$ 96,997
30	May-22	\$ 99,867	\$ (17,777)	\$ 5,294	\$ 87,383	May-22	\$ 96,997	\$ (17,419)	\$ 5,294	\$ 84,872
31	Jun-22	\$ 87,383	\$ (17,777)	\$ 5,294	\$ 74,900	Jun-22	\$ 84,872	\$ (17,419)	\$ 5,294	\$ 72,748
32	Jul-22	\$ 74,900	\$ (17,777)	\$ 5,294	\$ 62,417	Jul-22	\$ 72,748	\$ (17,419)	\$ 5,294	\$ 60,623
33	Aug-22	\$ 62,417	\$ (17,777)	\$ 5,294	\$ 49,933	Aug-22	\$ 60,623	\$ (17,419)	\$ 5,294	\$ 48,498
34	Sep-22	\$ 49,933	\$ (17,777)	\$ 5,294	\$ 37,450	Sep-22	\$ 48,498	\$ (17,419)	\$ 5,294	\$ 36,374
35	Oct-22	\$ 37,450	\$ (17,777)	\$ 5,294	\$ 24,967	Oct-22	\$ 36,374	\$ (17,419)	\$ 5,294	\$ 24,249
36	Nov-22	\$ 24,967	\$ (17,777)	\$ 5,294	\$ 12,483	Nov-22	\$ 24,249	\$ (17,419)	\$ 5,294	\$ 12,125
37	Dec-22	\$ 12,483	\$ (17,777)	\$ 5,294	\$ (0)	Dec-22	\$ 12,125	\$ (17,419)	\$ 5,294	\$ 0
Annual Totals										
38	2020		\$ (213,328)	\$ 63,528			\$ (209,024)	\$ 63,528		
39	2021		\$ (213,328)	\$ 63,528			\$ (209,024)	\$ 63,528		
40	2022		\$ (213,328)	\$ 63,528			\$ (209,024)	\$ 63,528		
13-Month Average Ending Balances										
41	2020				\$ 374,500					\$ 363,738
42	2021				\$ 224,700					\$ 218,243
43	2022				\$ 74,900					\$ 72,748

#### Notes and Source

Cols. A-E: Amounts from Attachment STF-L&A-1-39b

Cols. F-J: Staff amounts derived from page 1 and converted to monthly amounts as follows:

Test Year	Staff
Storm Damage	Projected
Monthly	Monthly
Accrual	Storm
Per Staff	Charges
\$ 436,486	\$ 63,528
3	12
\$ 145,495	\$ 5,294
\$ 63,528	
\$ 209,024	
12	
\$ 17,419	

Georgia Power Company  
Depreciation Expense and Accumulated Depreciation - Depreciation Rates

Retail Electric Amounts  
(Thousands of Dollars)

Exhibit (RS/RT-2)  
Schedule F-1  
Page 1 of 17

Line No.	Description	Forecasted Test Year Ending 7/31/2020 (A)	Calendar 2020 (B)	Calendar 2021 (C)	Calendar 2022 (D)	Reference
<b>Depreciation Expense</b>						
1	Total Company Depreciation Expense - Per Company	\$ 1,093,278	\$ 1,124,313	\$ 1,176,526	\$ 1,303,062	
2	Total Company Depreciation Expense - Per Staff	989,584	1,019,089	1,069,938	1,195,259	
3	Total Company Adjustment to Depreciation Expense	(103,694)	(105,223)	\$ (106,588)	\$ (107,804)	L2 - L1
4	Depreciation Expense Jurisdictional Factor	97.12000%	97.26577%	97.30497%	97.29600%	See Below
5	Jurisdictional Adjustment to Depreciation Expense	(100,707)	(102,346)	(103,716)	(104,889)	L3 x L4
<b>Accumulated Depreciation</b>						
6	Total Company Adjustment to Depreciation Expense - Forecasted Test Year Ending 7/31/2020	\$ (103,694)	\$ (105,223)			
7	Total Company Adjustment to Depreciation Expense - Calendar 2020			(106,588)		
8	Total Company Adjustment to Depreciation Expense - Calendar 2021				(107,804)	
9	Total Company Adjustment to Depreciation Expense - Calendar 2022				-0.5	
10	Multiply by 0.5	-0.5	-0.5	-0.5	-0.5	
11	One Half of Current Depreciation Expense Adjustment	\$ 51,847	\$ 52,612	\$ 53,294	\$ 53,902	
12	Prior Year's Depreciation Expense Adjustment	-	-	105,223	211,812	
13	Total Company Adjustment to Accumulated Depreciation	51,847	52,612	158,517	265,713	L11 + L12
14	Accumulated Depreciation Jurisdictional Factor	98.01715%	98.12450%	98.16681%	98.16981%	See Below
15	Jurisdictional Adjustment to Accumulated Depreciation	50,819	51,625	155,612	260,850	L13 x L14

Notes and Source:

Col. A, Line 1: Schedule F-1, page 3  
Col. A, Line 2: Schedule F-1, page 5  
Col. B, Line 1: Schedule F-1, page 7  
Col. B, Line 2: Schedule F-1, page 13  
Col. C, Line 1: Schedule F-1, page 9  
Col. C, Line 2: Schedule F-1, page 15  
Col. D, Line 1: Schedule F-1, page 11  
Col. D, Line 2: Schedule F-1, page 17

Line 4: Our depreciation expense adjustment reflects only a change to steam plant, therefore, we calculated a jurisdictional factor based on the Company's steam plant-in-service amounts and production accumulated depreciation amounts shown in Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company)  
Per Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company):

	Forecasted Test Year Ending 7/31/2020	Calendar 2020	Calendar 2021	Calendar 2022
Steam Plant-in-Service - Retail	\$ 9,594,779	\$ 9,716,382	\$ 9,816,569	\$ 9,905,027
Steam Plant-in-Service - Adjusted Electric	\$ 9,879,303	\$ 9,989,518	\$ 10,088,456	\$ 10,180,302
Depreciation Expense Jurisdictional Factor	97.12000%	97.26577%	97.30497%	97.29600%
Production Accumulated Depreciation - Retail	\$ 6,162,956	\$ 6,315,479	\$ 6,861,174	\$ 7,439,647
Production Accumulated Depreciation - Adjusted Electric	\$ 6,287,630	\$ 6,436,190	\$ 6,989,301	\$ 7,578,345
Accumulated Depreciation Jurisdictional Factor	98.01715%	98.12450%	98.16681%	98.16981%

Georgia Power Company  
Depreciation Expense  
Per Company  
Forecasted Test Year Ending July 31, 2020

Retail Electric Amounts  
(Thousands of Dollars)

Exhibit (RS/RT-2)  
Schedule F-1  
Page 2 of 17

Line No.	Description	Depr. Rate (A)	Jul-19 (B)	Aug-19 (C)	Sep-19 (D)	Oct-19 (E)	Nov-19 (F)	Dec-19 (G)	Jan-20 (H)	Feb-20 (I)	Mar-20 (J)	Apr-20 (K)	May-20 (L)	Jun-20 (M)	Jul-20 (N)	Total (O)
Steam Production- FERCs 310-312 & 314-316																
1	Bowen 1-4		4,682,430	4,681,009	4,686,229	4,696,629	4,710,439	4,781,234	4,731,331	4,712,248	4,730,429	4,759,405	4,927,924	4,807,598	4,808,401	
2	Scherer 1-3		1,432,126	1,431,973	1,431,496	1,429,968	1,428,546	1,524,325	1,523,909	1,523,511	1,523,112	1,522,721	1,522,323	1,521,969	1,521,564	
3	Wansley 1-2		969,113	968,937	971,458	1,022,761	1,022,761	1,026,671	1,026,671	1,027,473	1,027,866	1,028,271	1,028,773	1,029,254	1,029,734	
4	Yates 6-7		343,902	344,008	344,114	344,219	344,325	344,431	344,509	344,587	344,666	344,745	345,015	345,624	345,718	
5	McIntosh 1		47	52	56	61	66	120	120	120	120	120	120	120	120	
6	Total Depreciable balance		7,427,619	7,425,978	7,430,732	7,442,366	7,506,136	7,676,780	7,626,744	7,607,938	7,626,194	7,655,356	7,824,156	7,704,566	7,705,537	
7	Total Non Depreciable balance		2,289,020	2,289,023	2,289,021	2,289,277	2,289,533	2,289,835	2,290,167	2,290,499	2,290,831	2,291,165	2,291,240	2,291,315	2,291,390	
8	Total Steam		9,716,639	9,715,002	9,719,753	9,731,643	9,795,669	9,966,616	9,916,911	9,898,437	9,917,026	9,946,521	10,115,396	9,995,881	9,996,927	
Total Steam Depreciation Expense																
9	2019 Proposed Annual Rate	4.449%														
10	Monthly Calculated Expense		27,457	27,451	27,459	27,469	27,512	27,749	28,381	28,196	28,126	28,194	28,302	28,928	28,484	336,248
11	Manual Monthly Expense		5,099	5,099	5,099	5,099	5,099	5,099	5,297	5,297	5,297	5,297	5,297	5,297	5,297	65,569
12	Total Monthly Expense		33,156	33,150	33,158	33,211	33,447	33,678	33,492	33,492	33,492	33,490	33,598	34,224	33,781	401,818
Nuclear Production- FERCs 320-325																
13	Hatch 1-2		1,252,254	1,254,402	1,256,243	1,260,748	1,261,181	1,270,616	1,271,834	1,274,269	1,274,879	1,270,858	1,272,098	1,272,952	1,275,415	
Total Hatch Depreciation Expense																
14	2019 Proposed Annual Rate	3.046%														
15	Monthly Calculated Expense		3,179	3,184	3,189	3,189	3,200	3,201	3,225	3,228	3,235	3,236	3,226	3,229	3,231	
16	Manual Monthly Expense		(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	
17	Total Monthly Expense		3,146	3,151	3,156	3,156	3,167	3,168	3,225	3,228	3,235	3,236	3,226	3,229	3,231	
18	Vogtle 1&2 Common		849,125	850,523	851,476	851,772	852,038	862,021	862,234	862,628	863,418	863,358	863,899	865,857	866,741	
19	Vogtle 1		1,597,326	1,597,538	1,597,678	1,597,817	1,597,952	1,598,086	1,598,086	1,598,363	1,598,640	1,598,543	1,598,807	1,599,065	1,599,279	
20	Total Depreciable balance		2,446,451	2,448,062	2,449,154	2,449,589	2,449,990	2,460,107	2,460,321	2,461,045	2,462,058	2,461,901	2,462,706	2,464,922	2,466,020	
Total Vogtle 1&2 Comm. Unit 1 Depreciation Expense																
21	2019 Proposed Annual Rate	1.499%														
22	Monthly Calculated Expense		3,056	3,058	3,059	3,060	3,060	3,073	3,073	3,074	3,076	3,076	3,075	3,076	3,079	
23	Manual Monthly Expense		794	794	794	794	794	803	803	803	803	803	803	803	803	
24	Total Monthly Expense		3,850	3,852	3,854	3,854	3,854	3,855	3,876	3,876	3,877	3,878	3,878	3,879	3,882	
25	Vogtle 2		1,051,819	1,052,424	1,052,697	1,052,986	1,052,857	1,053,179	1,053,905	1,054,634	1,056,248	1,057,145	1,058,043	1,058,400	1,059,347	
Total Vogtle Unit 2 Depreciation Expense																
26	2019 Proposed Annual Rate	2.005%														
27	Monthly Calculated Expense		1,757	1,758	1,759	1,759	1,759	1,759	1,760	1,761	1,762	1,765	1,766	1,768	1,768	
28	Vogtle 3&4		30,210	30,210	30,211	30,211	30,257	30,257	30,257	30,257	30,257	30,257	30,257	30,303	30,303	
Total Vogtle Unit 3&4 Depreciation Expense																
29	2019 Proposed Annual Rate	1.768%														
30	Monthly Calculated Expense		45	45	45	45	45	45	45	45	45	45	45	45	45	
31	Total Non Depreciable balance		299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	
32	Total Nuclear Production		5,080,055	5,084,419	5,087,626	5,092,855	5,093,605	5,113,481	5,115,639	5,119,527	5,122,763	5,119,482	5,122,426	5,125,899	5,130,407	
Total Nuclear Depreciation Expense																
33	2019 Proposed Annual Rates															
34	Monthly Calculated Expense		8,037	8,045	8,052	8,064	8,064	8,065	8,103	8,107	8,115	8,121	8,112	8,118	8,123	97,062
35	Manual Monthly Expense		761	761	761	761	761	761	803	803	803	803	803	803	803	9,427
36	Total Monthly Expense		8,798	8,806	8,813	8,825	8,825	8,825	8,906	8,910	8,918	8,924	8,915	8,921	8,926	106,489
Hydro Production- FERCs 330-336																
37	Bartlett's Ferry		133,567	133,580	133,593	133,605	133,618	133,617	133,630	133,644	133,657	133,670	133,683	133,696	133,709	
38	Barton		12,915	12,922	12,928	12,934	12,940	12,940	12,946	12,952	12,959	12,965	12,971	12,978	12,984	
39	Central Ga Hys		195	201	207	213	219	219	225	232	238	244	251	257	263	
40	Flint River		20,372	20,440	20,509	21,734	21,734	21,734	21,873	22,012	22,151	22,290	22,429	22,568	22,707	
41	Goat Rock		31,392	31,399	31,405	31,418	31,418	31,418	32,576	33,734	34,893	37,110	38,178	39,336	40,494	
42	Lloyd Shoals		27,421	27,431	27,440	27,460	27,460	27,460	27,469	27,479	27,489	27,499	27,509	27,519	27,529	
43	Morgan Falls		10,505	10,669	10,833	11,071	11,235	11,350	11,366	11,381	11,397	11,413	11,429	11,444	11,460	
44	Nacoochee		7,740	7,746	7,752	7,758	7,764	7,764	7,771	7,777	7,783	7,790	7,796	7,802	7,809	
45	North Highlands		14,331	14,420	14,376	14,383	14,389	14,396	14,402	14,409	14,416	14,423	14,430	14,437	14,444	
46	Oliver Dam		20,551	20,557	20,594	20,600	20,607	20,613	20,620	20,627	20,634	20,641	20,648	20,655	20,662	
47	Sandbar Dam		22,510	22,508	23,106	23,403	23,701	23,991	25,034	26,078	27,122	28,166	29,210	30,254	31,297	
48	Tallahah Falls		30,436	30,196	30,202	30,209	30,215	30,222	30,228	30,235	30,242	30,249	30,256	30,263	30,270	
49	Terrora		18,219	18,219	18,232	18,239	18,245	18,252	18,258	18,265	18,272	18,279	18,286	18,293	18,300	
50	Tugalo		22,900	22,968	23,015	23,153	23,291	23,463	24,412	25,361	26,310	27,259	28,208	29,157	30,106	
51	Wallace Dam		198,604	198,627	198,651	198,675	198,699	198,733	199,360	199,790	200,173	200,556	200,939	201,322	201,705	
52	Yonah		9,740	9,747	9,753	9,760	9,766	9,766	9,773	9,779	9,786	9,793	9,800	9,806	9,813	
53	Rocky Mountain 1-3		179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	
54	Total Depreciable balance		760,486	761,333	762,194	764,196	764,899	765,707	769,501	773,296	777,090	781,944	785,819	789,783	793,478	
55	Total Non Depreciable balance		40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	
56	Total Hydro Production		800,494	801,342	802,202	804,204	804,908	805,715	809,510	813,304	817,099	821,952	825,827	829,792	833,486	
Total Hydro Depreciation Expense																
57	2019 Proposed Annual Rate	2.529%														
58	Monthly Calculated Expense		1,603	1,605	1,606	1,611	1,611	1,612	1,614	1,622	1,630	1,638	1,648	1,656	1,664	19,508
59	Manual Monthly Expense		9	9	9	9	9	9	17	17	17	17	17	17	163	
60	Total Monthly Expense		1,612	1,614	1,616	1,620	1,620	1,621	1,630	1,638	1,646	1,654	1,665	1,673	1,681	19,671
Other Production- FERCs 340-346																
61	Boulevard CT		1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	
62	Community Solar		3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	
63	Dalton Solar		12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	
64	Falkons Solar		3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	
65	Fort Benning Solar		65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	
66	Fort Gordon Solar		65,443	65,443	65,443	65,44										

Georgia Power Company  
Depreciation Expense  
Per Company  
Forecasted Test Year Ending July 31, 2020  
Retail Electric Amounts  
(Thousands of Dollars)

Exhibit (RS/RT-2)  
Schedule F-1  
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Line No.	Description	Depr. Rate (A)	Jul-19 (B)	Aug-19 (C)	Sep-19 (D)	Oct-19 (E)	Nov-19 (F)	Dec-19 (G)	Jan-20 (H)	Feb-20 (I)	Mar-20 (J)	Apr-20 (K)	May-20 (L)	Jun-20 (M)	Jul-20 (N)	Total (O)
<b>Total Other Depreciation Expense</b>																
87	2019 Proposed Annual Rates															
88	Monthly Calculated Expense		8,127		8,131	8,142	8,123	8,131	8,140	8,162	8,278	8,531	8,565	8,618	8,622	99,572
89	Manual Monthly Expense		3		3	3	3	3	3	3	3	3	3	3	3	42
90	Total Monthly Expense		8,130		8,134	8,146	8,127	8,134	8,144	8,166	8,281	8,535	8,569	8,622	8,626	99,614
<b>Transmission Plant- FERC's 350-359</b>																
91	Total Depreciable balance		5,875,520	5,903,109	5,943,324	5,971,613	6,022,195	6,056,860	6,170,503	6,207,836	6,223,909	6,235,694	6,252,146	6,330,941	6,281,608	
92	Non Depreciable balance		423,510	423,969	422,919	423,940	423,355	426,241	426,292	427,469	427,520	427,572	427,624	427,676	427,879	
93	Total Transmission Plant		6,299,031	6,325,078	6,366,242	6,394,053	6,445,551	6,483,101	6,596,796	6,635,305	6,651,430	6,663,266	6,679,770	6,758,617	6,709,487	
<b>Transmission Depreciation Expense</b>																
94	2019 Proposed Annual Rate	2.196%														
95	Monthly Calculated Expense		10,752		10,803	10,876	10,928	11,021	11,084	11,292	11,360	11,390	11,411	11,441	11,586	133,944
96	Manual Monthly Expense		440		440	440	440	440	438	438	438	438	438	438	438	5,262
97	Total Monthly Expense		11,192		11,242	11,316	11,368	11,460	11,522	11,730	11,798	11,828	11,849	11,879	12,023	139,207
<b>Distribution Plant- FERC's 360-362 &amp; 364-373</b>																
98	Total Depreciable balance		10,075,777	10,127,885	10,179,658	10,229,260	10,295,208	10,337,178	10,366,786	10,396,269	10,468,374	10,511,731	10,536,028	10,610,307	10,662,196	
99	Non Depreciable balance		153,420	153,420	160,118	160,118	160,234	160,790	160,790	160,790	160,790	160,790	160,790	160,790	160,990	
100	Total Distribution Plant		10,229,197	10,281,305	10,339,777	10,389,378	10,455,442	10,497,967	10,527,576	10,557,059	10,629,163	10,672,520	10,696,817	10,771,096	10,823,186	
<b>Distribution Depreciation Expense</b>																
101	2019 Proposed Annual Rate	2.27%														
102	Monthly Calculated Expense		22,670		22,788	22,904	23,016	23,164	23,259	23,325	23,392	23,554	23,651	23,706	23,873	
103	Manual Monthly Expense		150		150	150	150	150	152	152	152	152	152	152	153	
104	Total Monthly Expense		22,820		22,938	23,054	23,166	23,314	23,411	23,477	23,544	23,706	23,803	23,858	24,026	
105	Total GPC Unregulated ODL Depreciable balance		506,658	514,043	520,960	528,815	536,186	543,575	549,676	555,758	562,407	570,044	577,702	585,908	594,082	
<b>Distribution - Unregulated ODL</b>																
106	2019 Proposed Annual Rate	3.47%														
107	Monthly Calculated Expense			1,465	1,486	1,506	1,529	1,550	1,572	1,589	1,607	1,626	1,648	1,671	1,694	
<b>Total Distribution Depreciation Expense</b>																
108	2019 Proposed Annual Rates															
109	Monthly Calculated Expense		24,136		24,274	24,411	24,545	24,715	24,830	24,915	24,999	25,180	25,300	25,377	25,567	298,248
110	Manual Monthly Expense		150		150	150	150	150	152	152	152	152	152	152	153	1,814
111	Total Monthly Expense		24,285		24,424	24,561	24,695	24,865	24,982	25,067	25,151	25,332	25,452	25,529	25,720	300,062
<b>General Plant- FERC's 280, 390, 392.1-4, 396, &amp; 397</b>																
<b>General Plant Balances</b>																
112	390 Structures		383,807	387,446	391,084	394,723	398,362	362,087	366,689	371,291	375,894	419,671	424,273	428,875	429,712	
113	392 Transportation Equipment		353,379	356,728	360,076	363,424	366,772	370,136	373,571	377,007	380,442	383,877	387,312	390,747	394,182	
114	396 Power Operated Equipment		28,843	29,343	29,844	30,344	30,844	31,347	31,860	32,374	32,887	33,400	33,913	34,427	34,940	
115	397 Communications		382,551	386,733	391,024	395,207	399,389	423,945	426,666	429,314	431,963	434,611	437,260	439,908	444,419	
116	Amortizable and Non Depreciable balance		425,781	427,950	430,533	433,056	435,382	437,590	427,789	429,662	431,530	515,584	517,664	519,742	521,784	
117	Total General Plant		1,274,262	1,288,200	1,302,561	1,316,754	1,330,749	1,325,105	1,326,575	1,339,647	1,352,715	1,387,143	1,390,422	1,413,698	1,425,037	
118	390 Structures															
119	Proposed Monthly Depreciation Rates	1.759%		563	568	573	579	584	531	538	544	551	615	622	629	
120	392 Transportation Equipment*															
121	Proposed Monthly Depreciation Rates	4.316%		1,271	1,283	1,295	1,307	1,319	1,331	1,344	1,356	1,368	1,381	1,393	1,405	
122	396 Power Operated Equipment*															
123	Proposed Monthly Depreciation Rates	11.2609%		271	276	280	285	290	294	299	304	309	314	318	323	
124	397 Communications															
125	Proposed Monthly Depreciation Rates	2.715%		866	875	885	894	904	959	965	971	977	983	989	995	
126	Amortizable and Non Depreciable															
127	Proposed Monthly Manual Expense		(778)		(760)	(741)	(725)	(711)	1,665	1,680	1,695	1,710	1,726	1,741	1,756	
128	Reclassified Transportation and Power Operated Equipment*															
129	Proposed Monthly Depreciation Rates		(1,542)	(1,559)	(1,575)	(1,592)	(1,609)	(1,626)	(1,643)	(1,660)	(1,677)	(1,694)	(1,712)	(1,729)		
<b>Total General Depreciation Expense</b>																
130	2019 Proposed Annual Rates															
131	Monthly Calculated Expense		1,428		1,443	1,458	1,473	1,488	1,490	1,503	1,516	1,528	1,598	1,611	1,624	18,160
132	Manual Monthly Expense		(778)		(760)	(741)	(725)	(711)	1,665	1,680	1,695	1,710	1,726	1,741	1,756	8,257
133	Total Monthly Expense		650		683	717	748	776	3,155	3,183	3,211	3,239	3,324	3,352	3,380	26,417
134	Total 2019 Proposed Annual Rates- Depreciation Expense		87,823	88,054	88,335	88,593	89,130	92,017	92,186	92,428	93,002	93,372	94,199	94,137	1,093,278	

Notes and Source:  
Per the attachment that was provided in the Company's response to STF-WDA-2-17

Georgia Power Company  
Depreciation Expense  
Per Staff  
Forecasted Test Year Ending July 31, 2020

Exhibit (RS/RT-2)  
Schedule F-1  
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Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Depr. Rate (A)	Jul-19 (B)	Aug-19 (C)	Sep-19 (D)	Oct-19 (E)	Nov-19 (F)	Dec-19 (G)	Jan-20 (H)	Feb-20 (I)	Mar-20 (J)	Apr-20 (K)	May-20 (L)	Jun-20 (M)	Jul-20 (N)	Total (O)
<b>Steam Production- FERC's 310-312 &amp; 314-316</b>																
1	Bowen 1-4		4,682,430	4,681,009	4,686,229	4,696,629	4,710,439	4,781,234	4,731,331	4,712,248	4,730,429	4,759,405	4,927,924	4,807,598	4,808,401	
2	Scherer 1-3		1,432,126	1,431,973	1,431,496	1,429,998	1,428,546	1,524,325	1,523,909	1,523,511	1,523,112	1,522,721	1,522,323	1,521,969	1,521,564	
3	Wansley 1-2		969,113	968,937	968,838	971,458	1,022,671	1,026,875	1,027,473	1,027,866	1,028,271	1,028,773	1,029,254	1,029,734	1,029,734	
4	Yates 6-7		343,902	344,008	344,114	344,219	344,325	344,431	344,509	344,587	344,666	344,739	345,015	345,624	345,718	
5	McIntosh 1		47	52	56	61	66	120	120	120	120	120	120	120	120	
6	<b>Total Depreciable balance</b>		<b>7,427,619</b>	<b>7,425,978</b>	<b>7,430,732</b>	<b>7,442,366</b>	<b>7,506,136</b>	<b>7,676,780</b>	<b>7,626,744</b>	<b>7,607,938</b>	<b>7,626,194</b>	<b>7,655,356</b>	<b>7,824,156</b>	<b>7,704,566</b>	<b>7,705,537</b>	
7	<b>Total Non Depreciable balance</b>		<b>2,289,020</b>	<b>2,289,023</b>	<b>2,289,021</b>	<b>2,289,277</b>	<b>2,289,533</b>	<b>2,289,835</b>	<b>2,290,167</b>	<b>2,290,499</b>	<b>2,290,831</b>	<b>2,291,165</b>	<b>2,291,240</b>	<b>2,291,315</b>	<b>2,291,390</b>	
8	<b>Total Steam</b>		<b>9,716,639</b>	<b>9,715,002</b>	<b>9,719,753</b>	<b>9,731,643</b>	<b>9,795,669</b>	<b>9,966,616</b>	<b>9,916,911</b>	<b>9,898,437</b>	<b>9,917,026</b>	<b>9,946,521</b>	<b>10,115,396</b>	<b>9,995,881</b>	<b>9,996,927</b>	
<b>Total Steam Depreciation Expense</b>																
9	<b>2019 Proposed Annual Rate</b>	<b>3.077%</b>														
10	Monthly Calculated Expense			18,990	18,986	18,998	19,028	19,191	19,629	19,501	19,452	19,499	19,574	20,007	19,700	232,555
11	Manual Monthly Expense			5,699	5,699	5,699	5,699	5,699	5,297	5,297	5,297	5,297	5,297	5,297	5,297	65,569
12	<b>Total Monthly Expense</b>			<b>24,689</b>	<b>24,684</b>	<b>24,697</b>	<b>24,726</b>	<b>24,890</b>	<b>24,925</b>	<b>24,797</b>	<b>24,749</b>	<b>24,796</b>	<b>24,871</b>	<b>25,303</b>	<b>24,997</b>	<b>298,124</b>
<b>Nuclear Production- FERC's 320-325</b>																
13	Hatch 1-2		1,252,254	1,254,402	1,256,243	1,260,748	1,261,181	1,270,616	1,271,834	1,274,269	1,274,879	1,270,858	1,272,098	1,272,952	1,275,415	
14	<b>Total Hatch Depreciation Expense</b>															
15	<b>2019 Proposed Annual Rate</b>	<b>3.046%</b>														
16	Monthly Calculated Expense			3,179	3,184	3,189	3,200	3,201	3,225	3,228	3,235	3,236	3,226	3,229	3,231	
17	Manual Monthly Expense			(33)	(33)	(33)	(33)	(33)								
18	<b>Total Monthly Expense</b>			<b>3,146</b>	<b>3,151</b>	<b>3,156</b>	<b>3,167</b>	<b>3,168</b>	<b>3,225</b>	<b>3,228</b>	<b>3,235</b>	<b>3,236</b>	<b>3,226</b>	<b>3,229</b>	<b>3,231</b>	
19	Vogtle 1&2 Common		849,125	850,523	851,476	851,772	852,038	862,021	862,234	862,682	863,418	863,358	863,899	865,857	866,741	
20	Vogtle 1		1,597,326	1,597,538	1,597,678	1,597,817	1,597,952	1,598,086	1,598,087	1,598,363	1,598,640	1,598,543	1,598,807	1,599,065	1,599,279	
21	<b>Total Depreciable balance</b>		<b>2,446,451</b>	<b>2,448,062</b>	<b>2,449,154</b>	<b>2,449,589</b>	<b>2,449,990</b>	<b>2,460,107</b>	<b>2,460,321</b>	<b>2,461,045</b>	<b>2,462,058</b>	<b>2,461,901</b>	<b>2,462,706</b>	<b>2,464,922</b>	<b>2,466,020</b>	
<b>Total Vogtle 1&amp;2 Comm. Unit 1 Depreciation Expense</b>																
22	<b>2019 Proposed Annual Rate</b>	<b>1.499%</b>														
23	Monthly Calculated Expense			3,056	3,058	3,059	3,060	3,060	3,073	3,073	3,074	3,076	3,075	3,076	3,079	
24	Manual Monthly Expense			794	794	794	794	794	803	803	803	803	803	803	803	
25	<b>Total Monthly Expense</b>			<b>3,850</b>	<b>3,852</b>	<b>3,854</b>	<b>3,854</b>	<b>3,855</b>	<b>3,876</b>	<b>3,876</b>	<b>3,877</b>	<b>3,878</b>	<b>3,878</b>	<b>3,879</b>	<b>3,882</b>	
26	Vogtle 2		1,051,819	1,052,424	1,052,697	1,052,986	1,052,857	1,053,179	1,053,905	1,054,634	1,056,248	1,057,145	1,058,043	1,058,400	1,059,347	
27	<b>Total Vogtle Unit 2 Depreciation Expense</b>															
28	<b>2019 Proposed Annual Rate</b>	<b>2.005%</b>														
29	Monthly Calculated Expense			1,757	1,758	1,759	1,759	1,759	1,760	1,761	1,762	1,765	1,766	1,768	1,768	
30	<b>Total Monthly Expense</b>			<b>30,210</b>	<b>30,210</b>	<b>30,211</b>	<b>30,211</b>	<b>30,257</b>	<b>30,257</b>	<b>30,257</b>	<b>30,257</b>	<b>30,257</b>	<b>30,257</b>	<b>30,303</b>	<b>30,303</b>	
31	<b>Total Vogtle Unit 3&amp;4 Depreciation Expense</b>															
32	<b>2019 Proposed Annual Rate</b>	<b>1.768%</b>														
33	Monthly Calculated Expense			45	45	45	45	45	45	45	45	45	45	45	45	
34	<b>Total Monthly Expense</b>			<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	<b>45</b>	
35	<b>Total Nuclear Production</b>		<b>5,080,055</b>	<b>5,084,419</b>	<b>5,087,626</b>	<b>5,092,855</b>	<b>5,093,605</b>	<b>5,113,481</b>	<b>5,115,639</b>	<b>5,119,527</b>	<b>5,122,763</b>	<b>5,119,482</b>	<b>5,122,426</b>	<b>5,125,899</b>	<b>5,130,407</b>	
<b>Total Nuclear Depreciation Expense</b>																
36	<b>2019 Proposed Annual Rates</b>															
37	Monthly Calculated Expense			8,037	8,045	8,052	8,064	8,065	8,103	8,107	8,115	8,121	8,112	8,118	8,123	97,062
38	Manual Monthly Expense			761	761	761	761	761	803	803	803	803	803	803	803	9,427
39	<b>Total Monthly Expense</b>			<b>8,798</b>	<b>8,806</b>	<b>8,813</b>	<b>8,825</b>	<b>8,827</b>	<b>8,906</b>	<b>8,910</b>	<b>8,918</b>	<b>8,924</b>	<b>8,915</b>	<b>8,921</b>	<b>8,926</b>	<b>106,489</b>
<b>Hydro Production- FERC's 330-336</b>																
40	Bartlett's Ferry		133,567	133,580	133,593	133,605	133,618	133,617	133,630	133,644	133,657	133,670	133,683	133,696	133,709	
41	Burton		12,915	12,922	12,928	12,934	12,940	12,940	12,945	12,952	12,959	12,962	12,971	12,978	12,984	
42	Central Ga Hqs		195	201	207	213	219	219	225	232	238	244	251	257	263	
43	Flint River		20,372	20,440	20,509	21,734	21,734	21,873	22,012	22,151	22,290	22,429	22,568	22,707	22,846	
44	Goat Rock		31,392	31,399	31,405	31,412	31,418	31,418	32,576	33,734	34,893	37,110	38,178	39,336	40,494	
45	Lloyd Shoals		27,421	27,431	27,440	27,450	27,460	27,469	27,479	27,489	27,499	27,509	27,519	27,529	27,539	
46	Morgan Falls		10,505	10,669	10,833	11,071	11,235	11,350	11,366	11,381	11,397	11,413	11,429	11,444	11,460	
47	Nacoochee		7,740	7,746	7,752	7,758	7,764	7,764	7,771	7,777	7,783	7,789	7,796	7,802	7,809	
48	North Highlands		14,331	14,420	14,376	14,383	14,389	14,396	14,402	14,409	14,416	14,423	14,430	14,437	14,444	
49	Oliver Dam		20,551	20,757	20,594	20,600	20,607	20,607	20,613	20,620	20,627	20,633	20,639	20,645	20,651	
50	Sinclair Dam		22,510	22,808	23,106	23,403	23,701	23,991	25,034	26,078	27,122	28,166	29,210	30,254	31,297	
51	Tallulah Falls		30,436	30,196	30,202	30,209	30,215	30,215	30,222	30,228	30,235	30,242	30,249	30,255	30,262	
52	Terrora		18,219	18,226	18,232	18,239	18,245	18,252	18,258	18,265	18,272	18,279	18,285	18,292	18,299	
53	Tugalo		22,390	22,568	23,015	23,153	23,291	23,463	24,412	25,361	26,310	27,259	28,208	29,157	30,106	
54	Wallace Dam		198,604	198,627	198,651	198,675	198,699	198,723	199,346	199,759	200,173	200,586	200,999	201,412	201,825	
55	Yonah		9,740	9,747	9,753	9,760	9,766	9,773	9,779	9,786	9,793	9,800	9,806	9,813	9,819	
56	Rocky Mountain 1-3		179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	
57	<b>Total Depreciable balance</b>		<b>760,486</b>	<b>761,333</b>	<b>762,194</b>	<b>764,196</b>	<b>764,899</b>	<b>765,707</b>	<b>769,501</b>	<b>773,296</b>	<b>777,090</b>	<b>781,944</b>	<b>785,819</b>	<b>789,783</b>	<b>793,478</b>	
58	<b>Total Non Depreciable balance</b>		<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	
59	<b>Total Hydro Production</b>		<b>800,494</b>	<b>801,342</b>	<b>802,202</b>	<b>804,204</b>	<b>804,908</b>	<b>805,715</b>	<b>809,510</b>	<b>813,304</b>	<b>817,099</b>	<b>821,952</b>	<b>825,827</b>	<b>829,792</b>	<b>833,486</b>	
<b>Total Hydro Depreciation Expense</b>																
60	<b>2019 Proposed Annual Rate</b>	<b>2.529%</b>														
61	Monthly Calculated Expense			1,603	1,605	1,606	1,611	1,612	1,614	1,622	1,630	1,638	1,648	1,656	1,664	19,508
62	Manual Monthly Expense			9	9	9	9	9	17	17	17	17	17	17	17	163
63	<b>Total Monthly Expense</b>			<b>1,612</b>	<b>1,614</b>	<b>1,616</b>	<b>1,620</b>	<b>1,621</b>	<b>1,630</b>	<b>1,638</b>	<b>1,646</b>					

Georgia Power Company  
Depreciation Expense  
Per Staff  
Forecasted Test Year Ending July 31, 2020

Exhibit (RS/RT-2)  
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Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Depr. Rate (A)	Jul-19 (B)	Aug-19 (C)	Sep-19 (D)	Oct-19 (E)	Nov-19 (F)	Dec-19 (G)	Jan-20 (H)	Feb-20 (I)	Mar-20 (J)	Apr-20 (K)	May-20 (L)	Jun-20 (M)	Jul-20 (N)	Total (O)
<b>Total Other Depreciation Expense</b>																
87	<b>2019 Proposed Annual Rates</b>															
88	Monthly Calculated Expense			8,127	8,131	8,142	8,123	8,131	8,140	8,162	8,278	8,531	8,565	8,618	8,622	99,572
89	Manual Monthly Expense			3	3	3	3	3	3	3	3	3	3	3	3	42
90	Total Monthly Expense			8,130	8,134	8,146	8,127	8,134	8,144	8,166	8,281	8,535	8,569	8,622	8,626	99,614
<b>Transmission Plant- FERC's 350-359</b>																
91	Total Depreciable balance		5,875,520	5,903,109	5,943,324	5,971,613	6,022,195	6,056,860	6,170,503	6,207,836	6,223,909	6,235,694	6,252,146	6,330,941	6,281,608	
92	Non Depreciable balance		421,510	421,969	422,919	423,040	423,355	426,241	426,292	427,469	427,520	427,572	427,624	427,676	427,879	
93	Total Transmission Plant		<b>6,297,031</b>	<b>6,325,078</b>	<b>6,366,242</b>	<b>6,394,653</b>	<b>6,445,551</b>	<b>6,483,101</b>	<b>6,596,796</b>	<b>6,635,305</b>	<b>6,651,430</b>	<b>6,663,266</b>	<b>6,679,770</b>	<b>6,758,617</b>	<b>6,709,487</b>	
<b>Transmission Depreciation Expense</b>																
94	<b>2019 Proposed Annual Rate</b>	<b>2.196%</b>														
95	Monthly Calculated Expense			10,752	10,803	10,876	10,928	11,021	11,084	11,292	11,360	11,390	11,411	11,441	11,586	133,944
96	Manual Monthly Expense			440	440	440	440	440	438	438	438	438	438	438	438	5,262
97	Total Monthly Expense			11,192	11,242	11,316	11,368	11,460	11,522	11,730	11,798	11,828	11,849	11,879	12,023	139,207
<b>Distribution Plant- FERC's 360-362 &amp; 364-373</b>																
98	Total Depreciable balance		10,075,777	10,127,885	10,179,658	10,229,260	10,295,208	10,337,178	10,366,786	10,396,269	10,468,374	10,511,731	10,536,028	10,610,307	10,662,196	
99	Non Depreciable balance		153,420	153,420	160,118	160,118	160,234	160,790	160,790	160,790	160,790	160,790	160,790	160,790	160,990	
100	Total Distribution Plant		<b>10,229,197</b>	<b>10,281,305</b>	<b>10,339,777</b>	<b>10,389,378</b>	<b>10,455,442</b>	<b>10,497,967</b>	<b>10,527,576</b>	<b>10,557,059</b>	<b>10,629,163</b>	<b>10,672,520</b>	<b>10,696,817</b>	<b>10,771,096</b>	<b>10,823,186</b>	
<b>Distribution Depreciation Expense</b>																
101	<b>2019 Proposed Annual Rate</b>	<b>2.7%</b>														
102	Monthly Calculated Expense			22,670	22,788	22,904	23,016	23,164	23,259	23,325	23,392	23,554	23,651	23,706	23,873	
103	Manual Monthly Expense			150	150	150	150	150	152	152	152	152	152	152	153	
104	Total Monthly Expense			22,820	22,938	23,054	23,166	23,314	23,411	23,477	23,544	23,706	23,803	23,858	24,026	
105	Total GPC Unregulated ODL Depreciable balance		<b>506,658</b>	<b>514,043</b>	<b>520,960</b>	<b>528,815</b>	<b>536,186</b>	<b>543,575</b>	<b>549,676</b>	<b>555,758</b>	<b>562,407</b>	<b>570,044</b>	<b>577,702</b>	<b>585,908</b>	<b>594,082</b>	
<b>Distribution - Unregulated ODL</b>																
106	<b>2019 Proposed Annual Rate</b>	<b>3.47%</b>														
107	Monthly Calculated Expense			1,465	1,486	1,506	1,529	1,550	1,572	1,589	1,607	1,626	1,648	1,671	1,694	
<b>Total Distribution Depreciation Expense</b>																
108	<b>2019 Proposed Annual Rates</b>															
109	Monthly Calculated Expense			24,136	24,274	24,411	24,545	24,715	24,830	24,915	24,999	25,180	25,300	25,377	25,567	298,248
110	Manual Monthly Expense			150	150	150	150	150	152	152	152	152	152	152	153	1,814
111	Total Monthly Expense			24,285	24,424	24,561	24,695	24,865	24,982	25,067	25,151	25,332	25,452	25,529	25,720	300,062
<b>General Plant- FERC's 289, 390, 392.1-4, 396, &amp; 397</b>																
<b>General Plant Balances</b>																
112	390 Structures		383,807	387,446	391,084	394,723	398,362	362,087	366,689	371,291	375,894	419,671	424,273	428,875	429,712	
113	392 Transportation Equipment		353,379	356,728	360,076	363,424	366,772	370,136	373,571	377,007	380,442	383,877	387,312	390,747	394,182	
114	396 Power Operated Equipment		28,843	29,343	29,844	30,344	30,844	31,347	31,860	32,374	32,887	33,400	33,913	34,427	34,940	
115	397 Communications		382,551	386,733	391,024	395,207	399,389	423,945	426,666	429,314	431,963	434,611	437,260	439,908	444,419	
116	Amortizable and Non Depreciable balance		425,781	427,950	430,533	433,056	435,382	437,589	427,789	429,662	431,530	515,584	517,664	519,742	521,784	
117	Total General Plant		<b>1,574,362</b>	<b>1,588,200</b>	<b>1,602,561</b>	<b>1,616,754</b>	<b>1,630,749</b>	<b>1,625,105</b>	<b>1,626,575</b>	<b>1,639,647</b>	<b>1,652,715</b>	<b>1,787,143</b>	<b>1,800,422</b>	<b>1,813,698</b>	<b>1,825,037</b>	
118	390 Structures															
119	Proposed Monthly Depreciation Rates	<b>1.759%</b>		563	568	573	579	584	531	538	544	551	615	622	629	
120	392 Transportation Equipment*															
121	Proposed Monthly Depreciation Rates	<b>4.316%</b>		1,271	1,283	1,295	1,307	1,319	1,331	1,344	1,356	1,368	1,381	1,393	1,405	
122	396 Power Operated Equipment*															
123	Proposed Monthly Depreciation Rates	<b>11.269%</b>		271	276	280	285	290	294	299	304	309	314	318	323	
124	397 Communications															
125	Proposed Monthly Depreciation Rates	<b>2.715%</b>		866	875	885	894	904	959	965	971	977	983	989	995	
126	Amortizable and Non Depreciable															
127	Proposed Monthly Manual Expense			(778)	(760)	(741)	(725)	(711)	1,665	1,680	1,695	1,710	1,726	1,741	1,756	
128	Reclassified Transportation and Power Operated Equipment*															
129	Proposed Monthly Depreciation Rates			(1,542)	(1,559)	(1,575)	(1,592)	(1,609)	(1,626)	(1,643)	(1,660)	(1,677)	(1,694)	(1,712)	(1,729)	
<b>Total General Depreciation Expense</b>																
130	<b>2019 Proposed Annual Rates</b>															
131	Monthly Calculated Expense			1,428	1,443	1,458	1,473	1,488	1,490	1,503	1,516	1,528	1,598	1,611	1,624	18,160
132	Manual Monthly Expense			(778)	(760)	(741)	(725)	(711)	1,665	1,680	1,695	1,710	1,726	1,741	1,756	8,257
133	Total Monthly Expense			650	683	717	748	776	3,155	3,183	3,211	3,239	3,324	3,352	3,380	26,417
134	Total 2019 Proposed Annual Rates- Depreciation Expense		<b>79,356</b>	<b>79,588</b>	<b>79,864</b>	<b>80,109</b>	<b>80,573</b>	<b>83,265</b>	<b>83,491</b>	<b>83,755</b>	<b>84,308</b>	<b>84,644</b>	<b>85,278</b>	<b>85,353</b>	<b>989,584</b>	

Notes and Source:

Per the attachment that was provided in the Company's response to STF-WDA-2-17

Col A: Per the recommended depreciation rates by Staff witness William Dunkel



Retail Electric Amounts  
(Thousands of Dollars)[illegible]

Georgia Power Company  
Depreciation Expense  
Per Company  
Calendar Year 2020

Schedule F-1  
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Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Depr. Rate (A)	Dec-19 (B)	Jan-20 (C)	Feb-20 (D)	Mar-20 (E)	Apr-20 (F)	May-20 (G)	Jun-20 (H)	Jul-20 (I)	Aug-20 (J)	Sep-20 (K)	Oct-20 (L)	Nov-20 (M)	Dec-20 (N)
<b>Transmission Plant- FERC's 350-359</b>															
91	Total Depreciable balance		6,056,860	6,170,503	6,207,836	6,223,909	6,235,694	6,252,146	6,330,941	6,281,608	6,301,979	6,346,951	6,390,665	6,422,112	6,461,104
92	Non Depreciable balance		426,241	426,292	427,469	427,520	427,572	427,624	427,676	427,879	428,032	428,186	428,340	428,494	428,798
93	Total Transmission Plant		<b>6,483,101</b>	<b>6,596,796</b>	<b>6,635,305</b>	<b>6,651,430</b>	<b>6,663,266</b>	<b>6,679,770</b>	<b>6,758,617</b>	<b>6,709,487</b>	<b>6,730,012</b>	<b>6,775,137</b>	<b>6,819,004</b>	<b>6,850,605</b>	<b>6,889,902</b>
<b>Transmission Depreciation Expense</b>															
94	2019 Proposed Annual Rate	2.196%													
95	Monthly Calculated Expense			11,072	11,280	11,349	11,378	11,400	11,430	11,574	11,484	11,521	11,603	11,683	11,741
96	Manual Monthly Expense			450	450	450	450	450	450	450	450	450	450	450	450
97	Total Monthly Expense			11,522	11,730	11,798	11,828	11,849	11,879	12,023	11,933	11,970	12,053	12,133	12,190
<b>Distribution Plant- FERC's 360-362 &amp; 364-373</b>															
98	Total Depreciable balance		10,337,286	10,366,894	10,396,377	10,468,482	10,511,839	10,536,136	10,610,415	10,662,304	10,711,405	10,814,619	10,862,736	10,911,698	11,020,347
99	Non Depreciable balance		160,790	160,790	160,790	160,790	160,790	160,790	160,790	160,990	160,990	160,990	160,990	160,990	161,740
100	Total Distribution Plant		<b>10,498,075</b>	<b>10,527,684</b>	<b>10,557,167</b>	<b>10,629,271</b>	<b>10,672,628</b>	<b>10,696,925</b>	<b>10,771,204</b>	<b>10,823,294</b>	<b>10,872,395</b>	<b>10,975,608</b>	<b>11,023,726</b>	<b>11,072,687</b>	<b>11,182,086</b>
<b>Distribution Depreciation Expense</b>															
101	2019 Proposed Annual Rate	2.7%													
102	Monthly Calculated Expense			23,259	23,325	23,392	23,554	23,651	23,706	23,873	23,990	24,100	24,333	24,441	24,551
103	Manual Monthly Expense			153	153	153	153	153	153	153	153	153	153	153	153
104	Total Monthly Expense			23,412	23,478	23,545	23,707	23,805	23,859	24,027	24,143	24,254	24,486	24,594	24,704
105	Total GPC Unregulated ODL Depreciable balance		<b>543,575</b>	<b>549,676</b>	<b>555,758</b>	<b>562,407</b>	<b>570,844</b>	<b>577,702</b>	<b>585,908</b>	<b>594,882</b>	<b>602,745</b>	<b>610,926</b>	<b>620,873</b>	<b>628,721</b>	<b>637,393</b>
<b>Distribution - Unregulated ODL</b>															
106	2019 Proposed Annual Rate	3.47%													
107	Monthly Calculated Expense			1,572	1,589	1,607	1,626	1,648	1,671	1,694	1,718	1,743	1,767	1,793	1,818
<b>Total Distribution Depreciation Expense</b>															
108	2019 Proposed Annual Rates														
109	Monthly Calculated Expense			24,830	24,915	24,999	25,180	25,300	25,377	25,567	25,708	25,843	26,099	26,234	26,369
110	Manual Monthly Expense			152	152	152	152	152	152	152	152	152	152	152	152
111	Total Monthly Expense			24,983	25,067	25,151	25,332	25,452	25,529	25,719	25,860	25,995	26,251	26,386	26,521
<b>General Plant- FERC's 289, 390, 392, 1-A, 396, &amp; 397</b>															
<b>General Plant Balances</b>															
112	390 Structures		362,087	366,689	371,291	375,894	419,671	424,273	428,875	429,712	434,314	438,916	443,518	448,120	452,744
113	392 Transportation Equipment		370,136	373,571	377,007	380,442	383,877	387,312	390,747	394,182	397,617	401,052	404,488	407,923	411,374
114	396 Power Operated Equipment		31,347	31,860	32,374	32,887	33,400	33,913	34,427	34,940	35,453	35,967	36,480	36,993	37,509
115	397 Communications		423,945	426,666	429,314	431,963	434,611	437,260	439,908	444,419	448,929	453,440	457,951	462,461	466,260
116	Amortizable and Non Depreciable balance		437,589	427,789	429,662	431,530	515,584	517,664	519,742	521,784	523,819	525,859	527,898	529,938	531,987
117	Total General Plant		<b>1,625,105</b>	<b>1,626,575</b>	<b>1,639,647</b>	<b>1,652,715</b>	<b>1,787,143</b>	<b>1,800,422</b>	<b>1,813,698</b>	<b>1,825,037</b>	<b>1,840,133</b>	<b>1,855,234</b>	<b>1,870,334</b>	<b>1,885,435</b>	<b>1,899,875</b>
118	390 Structures														
119	Proposed Monthly Depreciation Rates	1.759%		531	538	544	551	615	622	629	630	637	643	650	657
120	392 Transportation Equipment*														
121	Proposed Monthly Depreciation Rates	4.316%		1,331	1,344	1,356	1,368	1,381	1,393	1,405	1,418	1,430	1,442	1,455	1,467
122	396 Power Operated Equipment*														
123	Proposed Monthly Depreciation Rates	11.269%		294	299	304	309	314	318	323	328	333	338	343	347
124	397 Communications														
125	Proposed Monthly Depreciation Rates	2.715%		959	965	971	977	983	989	995	1,005	1,016	1,026	1,036	1,046
126	Amortizable and Non Depreciable														
127	Proposed Monthly Manual Expense			1,665	1,680	1,695	1,710	1,726	1,741	1,756	1,771	1,786	1,801	1,096	1,106
128	Reclassified Transportation and Power Operated Equipment*														
129	Proposed Monthly Depreciation Rates			(1,626)	(1,643)	(1,660)	(1,677)	(1,694)	(1,712)	(1,729)	(1,746)	(1,763)	(1,780)	(1,797)	(1,815)
<b>Total General Depreciation Expense</b>															
130	2019 Proposed Annual Rates														
131	Monthly Calculated Expense			1,490	1,503	1,516	1,528	1,598	1,611	1,624	1,635	1,652	1,669	1,686	1,703
132	Manual Monthly Expense			1,665	1,680	1,695	1,710	1,726	1,741	1,756	1,771	1,786	1,801	1,096	1,106
133	Total Monthly Expense			3,155	3,183	3,211	3,239	3,324	3,352	3,380	3,406	3,438	3,470	2,782	2,810
<b>Total Company Depreciation Expense</b>															
134	2019 Proposed Annual Rates														
135	Monthly Calculated Expense			83,630	83,785	84,012	84,570	84,925	85,737	85,659	85,745	85,963	86,471	86,724	86,902
136	Manual Monthly Expense			8,387	8,402	8,417	8,432	8,447	8,462	8,477	8,492	8,507	8,522	7,817	7,827
137	Total Monthly Expense			92,017	92,186	92,428	93,002	93,372	94,199	94,137	94,237	94,471	94,994	94,541	94,729
138	Total Annual Depreciation Expense													<b>Calendar Year 2020</b>	<b>1,124,313</b>

Notes and Source:

Per the attachment provided in the Company's response to STF-L&A-2-3 and STF-L&A-2-4

Retail Electric Amount  
(Thousands of Dollars)

Line No.	Description	Dep'r. Rate	Jan-21 (A)	Feb-21 (P)	Mar-21 (Q)	Apr-21 (R)	May-21 (S)	Jun-21 (T)	Jul-21 (U)	Aug-21 (V)	Sep-21 (W)	Oct-21 (X)	Nov-21 (Y)	Dec-21 (Z)
<b>Steam Production - FERC's 310-312 &amp; 314-316</b>														
1	Brown 1-2		4,857,047	4,852,822	4,872,385	4,889,798	4,887,257	4,883,084	4,880,374	4,878,446	4,886,186	4,892,439	4,890,574	4,913,336
2	Schrier 1-3		1,520,827	1,520,717	1,520,608	1,530,836	1,530,825	1,531,594	1,531,622	1,531,558	1,531,506	1,531,454	1,531,402	1,538,907
3	Wansley 1-2		1,035,607	1,035,636	1,035,665	1,035,694	1,035,791	1,035,887	1,035,983	1,036,079	1,036,175	1,036,271	1,036,367	1,038,135
4	Yates 6-7		346,198	346,275	346,411	346,630	346,853	346,914	346,974	347,034	347,095	347,155	347,215	347,276
5	Michoud 1-2		120	120	120	120	120	120	120	120	120	120	120	120
6	<b>Total Depreciable balance</b>		<b>7,259,599</b>	<b>7,255,571</b>	<b>7,275,189</b>	<b>7,303,078</b>	<b>7,300,846</b>	<b>7,297,598</b>	<b>7,295,073</b>	<b>7,293,237</b>	<b>7,300,882</b>	<b>7,307,439</b>	<b>7,314,680</b>	<b>7,337,774</b>
7	<b>Total Non Depreciable balance</b>		<b>2,292,596</b>	<b>2,292,688</b>	<b>2,293,780</b>	<b>2,293,871</b>	<b>2,293,963</b>	<b>2,294,055</b>	<b>2,294,146</b>	<b>2,294,238</b>	<b>2,294,330</b>	<b>2,295,291</b>	<b>2,295,621</b>	<b>2,295,713</b>
8	<b>Total Steam</b>		<b>10,052,195</b>	<b>10,048,259</b>	<b>10,068,969</b>	<b>10,096,949</b>	<b>10,094,809</b>	<b>10,091,653</b>	<b>10,089,219</b>	<b>10,087,475</b>	<b>10,095,412</b>	<b>10,102,730</b>	<b>10,110,480</b>	<b>10,133,487</b>
<b>Total Steam Depreciation Expense</b>														
9	2019 Proposed Annual Rate	4.449%												
10	Monthly Calculated Expense		28,773	28,689	28,673	28,746	28,849	28,841	28,829	28,820	28,813	28,842	28,866	28,893
11	Manual Monthly Expense		5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297
12	<b>Total Monthly Expense</b>		<b>34,070</b>	<b>33,986</b>	<b>33,970</b>	<b>34,043</b>	<b>34,146</b>	<b>34,138</b>	<b>34,126</b>	<b>34,116</b>	<b>34,110</b>	<b>34,139</b>	<b>34,162</b>	<b>34,190</b>
<b>Nuclear Production - FERC's 320-325</b>														
13	Hatch 1-2		1,294,308	1,297,786	1,298,655	1,313,811	1,315,747	1,322,597	1,324,625	1,326,627	1,330,689	1,332,934	1,335,066	1,337,198
<b>Total Hatch Depreciation Expense</b>														
14	2019 Proposed Annual Rate	3.046%												
15	Monthly Calculated Expense		3,281	3,285	3,294	3,296	3,335	3,340	3,357	3,362	3,367	3,378	3,383	3,389
16	Manual Monthly Expense		-	-	-	-	-	-	-	-	-	-	-	-
17	<b>Total Monthly Expense</b>		<b>3,281</b>	<b>3,285</b>	<b>3,294</b>	<b>3,296</b>	<b>3,335</b>	<b>3,340</b>	<b>3,357</b>	<b>3,362</b>	<b>3,367</b>	<b>3,378</b>	<b>3,383</b>	<b>3,389</b>
18	Vogtle 1&2 Common		870,082	870,763	871,443	872,123	872,795	873,460	874,125	874,791	876,672	877,337	886,696	888,126
19	Vogtle 1		1,602,488	1,603,114	1,603,732	1,604,416	1,605,853	1,605,417	1,605,979	1,606,542	1,607,105	1,607,667	1,608,229	1,607,107
20	<b>Total Depreciable balance</b>		<b>2,472,571</b>	<b>2,473,877</b>	<b>2,475,175</b>	<b>2,476,294</b>	<b>2,477,658</b>	<b>2,478,877</b>	<b>2,480,105</b>	<b>2,481,332</b>	<b>2,483,777</b>	<b>2,484,958</b>	<b>2,493,287</b>	<b>2,495,233</b>
<b>Total Vogtle 1&amp;2 Comm. Unit 1 Depreciation Expense</b>														
21	2019 Proposed Annual Rate	1.499%												
22	Monthly Calculated Expense		3,087	3,089	3,090	3,092	3,093	3,095	3,097	3,098	3,100	3,103	3,104	3,115
23	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
24	<b>Total Monthly Expense</b>		<b>3,890</b>	<b>3,892</b>	<b>3,893</b>	<b>3,895</b>	<b>3,896</b>	<b>3,898</b>	<b>3,900</b>	<b>3,901</b>	<b>3,903</b>	<b>3,906</b>	<b>3,907</b>	<b>3,918</b>
25	Vogtle 2		1,067,285	1,067,570	1,068,134	1,068,411	1,068,692	1,068,970	1,069,246	1,069,518	1,069,963	1,070,356	1,070,655	1,073,745
<b>Total Vogtle Unit 2 Depreciation Expense</b>														
26	2019 Proposed Annual Rate - 2.005%	2.005%												
27	Monthly Calculated Expense		1,780	1,783	1,784	1,785	1,785	1,786	1,786	1,787	1,787	1,788	1,788	1,789
28	Vogtle 3&4		30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	4,584,783
<b>Total Vogtle Unit 3&amp;4 Depreciation Expense</b>														
29	2019 Proposed Annual Rate	1.768%												
30	Monthly Calculated Expense		45	45	45	45	45	45	45	45	45	45	45	6,755
31	<b>Total Non Depreciable balance</b>		<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>
32	<b>Total Nuclear Production</b>		<b>5,163,836</b>	<b>5,168,994</b>	<b>5,171,635</b>	<b>5,188,310</b>	<b>5,191,761</b>	<b>5,200,116</b>	<b>5,203,648</b>	<b>5,207,150</b>	<b>5,214,100</b>	<b>5,217,019</b>	<b>5,283,113</b>	<b>9,791,054</b>
<b>Total Nuclear Depreciation Expense</b>														
33	2019 Proposed Annual Rate													
34	Monthly Calculated Expense		8,192	8,202	8,213	8,218	8,258	8,265	8,285	8,292	8,299	8,313	8,321	15,047
35	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
36	<b>Total Monthly Expense</b>		<b>8,995</b>	<b>9,005</b>	<b>9,016</b>	<b>9,021</b>	<b>9,061</b>	<b>9,068</b>	<b>9,087</b>	<b>9,095</b>	<b>9,102</b>	<b>9,116</b>	<b>9,124</b>	<b>15,850</b>
<b>Hydro Production - FERC's 330-336</b>														
37	Bartlett's Ferry		133,774	133,788	133,801	133,815	133,828	133,842	133,855	133,868	133,882	133,895	133,909	133,909
38	Barton		13,016	13,022	13,029	13,035	13,042	13,048	13,055	13,058	13,062	13,065	13,068	13,075
39	Chickasaw Gap Hqs		302	302	302	302	302	302	302	302	302	302	302	302
40	Flint River		24,440	25,266	26,091	26,917	27,742	28,568	29,393	30,291	31,190	32,089	32,914	33,743
41	Goat Rock		47,393	52,649	57,905	63,161	68,417	73,673	78,960	84,319	89,678	95,355	101,032	87,962
42	Lloyd Shoals		27,578	27,588	27,597	27,609	27,619	27,629	27,639	27,649	27,660	27,670	27,680	27,690
43	Morgan Falls		11,654	11,693	11,732	11,772	11,811	11,850	11,890	11,929	11,968	12,008	12,048	12,088
44	Nacoochee		7,840	7,847	7,853	7,860	7,866	7,873	7,879	7,886	7,893	7,900	7,907	7,914
45	North Highlands		15,028	15,474	15,920	16,365	16,808	17,251	17,694	18,137	18,580	19,023	19,466	19,909
46	Oliver Dam		21,256	21,511	21,767	22,022	22,278	22,533	22,788	23,044	23,299	23,555	23,810	24,066
47	Sandbar Dam		38,828	41,144	43,461	45,777	48,093	50,410	52,726	55,042	57,359	59,675	61,991	64,307
48	Tallahassee Falls		30,296	30,303	30,310	30,317	30,323	30,330	30,337	30,344	30,351	30,358	30,365	30,365
49	Terrona		36,126	38,333	40,540	42,747	44,954	47,161	49,368	51,575	53,782	55,989	58,196	60,403
50	Wallace Dam		205,858	207,841	209,824	211,808	213,791	215,774	217,758	219,741	221,724	223,707	225,691	227,664
51	Yonah		9,847	9,854	9,861	9,868	9,875	9,882	9,889	9,896	9,902	9,909	9,916	9,924
52	Rocky Mountain 1-3		179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	100,047
53	<b>Total Depreciable balance</b>		<b>821,608</b>	<b>835,537</b>	<b>849,473</b>	<b>863,502</b>	<b>877,537</b>	<b>891,568</b>	<b>905,600</b>	<b>919,632</b>	<b>933,664</b>	<b>947,696</b>	<b>961,728</b>	<b>975,760</b>
54	<b>Total Non Depreciable balance</b>		<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>
55	<b>Total Hydro Production</b>		<b>861,609</b>	<b>874,455</b>	<b>887,482</b>	<b>903,510</b>	<b>917,545</b>	<b>931,576</b>	<b>945,608</b>	<b>959,640</b>	<b>973,672</b>	<b>987,704</b>	<b>1,001,736</b>	<b>1,015,768</b>
<b>Total Hydro Depreciation Expense</b>														
57	2019 Proposed Annual Rate	2.529%												
58	Monthly Calculated Expense		1,659	1,732	1,759	1,786	1,816	1,843	1,871	1,898	1,926	1,954	1,983	2,011
59	Manual Monthly Expense		17	17	17	17	17	17	17	17	17	17	17	17
60	<b>Total Monthly Expense</b>		<b>1,675</b>	<b>1,748</b>	<b>1,776</b>	<b>1,803</b>	<b>1,832</b>	<b>1,860</b>	<b>1,887</b>	<b>1,914</b>	<b>1,943</b>	<b>1,971</b>	<b>1,999</b>	<b>2,027</b>
<b>Other Production - FERC's 340-346</b>														
61	Bowdoin CT		1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
62	Community Solar		3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143
63	Dalbousville CT		12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553
64	Falcons Solar		3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379
65	Fort Benning Solar		65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636
66	Fort Gordon Solar		65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443
67	Fort Stewart Solar		66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652
68	Kings Bay Solar		66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956
69	Marine Corps - Albany Solar		406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278
70	Marine Corps CC CT		13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084
71	McIntosh CC CT		720,377	721,195	722,013	722,831	723,649	724,467	725,285	726,103	726,921	727,739	728,557	729,375
72	McIntosh CTs		227,568	227,040	226,512	225,984	225,456	224,928	224,400	223,872	223,344	222,816	222,288	221,760
73	Memphis CT		61,037	61,013	61,017	61,034	61,039	61,043	61,047	61,051	61,055	61,059	61,063	61,067
74	North Carolina Solar		1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801
75	University of Georgia Solar		4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569
76	Wansley CT		7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,3	

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Retail Electric Amounts  
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Line No.	Description	Depr. Rate (A)	Jan-21 (D)	Feb-21 (E)	Mar-21 (F)	Apr-21 (G)	May-21 (H)	Jun-21 (I)	Jul-21 (J)	Aug-21 (K)	Sep-21 (L)	Oct-21 (M)	Nov-21 (N)	Dec-21 (O)
<b>Transmission Plant- FERC's 350-359</b>														
91	Total Depreciable balance		6,493,419	6,531,311	6,536,683	6,550,419	6,570,876	6,585,247	6,617,429	6,639,265	6,659,048	6,673,439	6,695,940	6,721,023
92	Non Depreciable balance		429,183	429,235	429,787	429,840	430,094	430,147	430,303	430,460	430,616	430,773	430,931	431,239
93	<b>Total Transmission Plant</b>		<b>6,922,602</b>	<b>6,960,546</b>	<b>6,966,471</b>	<b>6,980,259</b>	<b>7,000,969</b>	<b>7,015,394</b>	<b>7,047,732</b>	<b>7,069,724</b>	<b>7,089,665</b>	<b>7,104,212</b>	<b>7,126,871</b>	<b>7,152,263</b>
<b>Transmission Depreciation Expense</b>														
94	2019 Proposed Annual Rate	2.196%												
95	Monthly Calculated Expense		11,812	11,871	11,941	11,950	11,975	12,013	12,039	12,098	12,138	12,174	12,201	12,242
96	Manual Monthly Expense		450	450	450	450	450	450	450	450	450	450	450	450
97	<b>Total Monthly Expense</b>		<b>12,262</b>	<b>12,321</b>	<b>12,390</b>	<b>12,400</b>	<b>12,425</b>	<b>12,462</b>	<b>12,489</b>	<b>12,548</b>	<b>12,588</b>	<b>12,624</b>	<b>12,650</b>	<b>12,691</b>
<b>Distribution Plant- FERC's 360-362 &amp; 364-373</b>														
98	Total Depreciable balance		11,040,503	11,081,862	11,210,077	11,233,016	11,257,496	11,388,683	11,442,366	11,490,200	11,634,506	11,681,823	11,727,425	11,888,060
99	Non Depreciable balance		161,740	162,090	162,283	162,283	162,283	162,283	162,283	162,283	162,283	162,283	162,283	162,283
100	<b>Total Distribution Plant</b>		<b>11,202,243</b>	<b>11,243,952</b>	<b>11,372,360</b>	<b>11,395,299</b>	<b>11,419,779</b>	<b>11,550,967</b>	<b>11,604,649</b>	<b>11,652,483</b>	<b>11,796,789</b>	<b>11,844,106</b>	<b>11,889,708</b>	<b>12,050,344</b>
<b>Distribution Depreciation Expense</b>														
101	2019 Proposed Annual Rate	2.7%												
102	Monthly Calculated Expense		24,796	24,841	24,934	25,222	25,274	25,329	25,624	25,745	25,853	26,177	26,284	26,386
103	Manual Monthly Expense		153	153	153	153	153	153	153	153	153	153	153	153
104	<b>Total Monthly Expense</b>		<b>24,949</b>	<b>24,994</b>	<b>25,087</b>	<b>25,376</b>	<b>25,427</b>	<b>25,483</b>	<b>25,778</b>	<b>25,898</b>	<b>26,006</b>	<b>26,331</b>	<b>26,437</b>	<b>26,540</b>
105	<b>Total GPC Unregulated ODL Depreciable balance</b>		<b>642,966</b>	<b>648,519</b>	<b>654,656</b>	<b>661,812</b>	<b>668,987</b>	<b>676,728</b>	<b>684,436</b>	<b>692,647</b>	<b>700,361</b>	<b>709,072</b>	<b>717,268</b>	<b>725,485</b>
<b>Distribution - Unregulated ODL</b>														
106	2019 Proposed Annual Rate	3.47%												
107	Monthly Calculated Expense		1,843	1,859	1,875	1,893	1,914	1,934	1,957	1,979	2,003	2,025	2,050	2,074
<b>Total Distribution Depreciation Expense</b>														
108	2019 Proposed Annual Rates													
109	Monthly Calculated Expense		26,639	26,700	26,809	27,115	27,188	27,264	27,581	27,724	27,856	28,203	28,334	28,461
110	Manual Monthly Expense		152	152	152	152	152	152	152	152	152	152	152	152
111	<b>Total Monthly Expense</b>		<b>26,790</b>	<b>26,852</b>	<b>26,961</b>	<b>27,267</b>	<b>27,340</b>	<b>27,415</b>	<b>27,733</b>	<b>27,876</b>	<b>28,007</b>	<b>28,354</b>	<b>28,486</b>	<b>28,612</b>
<b>General Plant- FERC's 289, 390, 392.1-4, 396, &amp; 397</b>														
<b>General Plant Balances</b>														
112	390 Structures		458,228	463,712	469,196	474,680	480,164	485,648	491,132	496,616	502,100	507,584	513,068	518,578
113	392 Transportation Equipment		414,853	418,331	421,810	425,289	428,767	432,246	435,725	439,203	442,682	446,160	449,639	453,134
114	396 Power Operated Equipment		38,029	38,549	39,068	39,588	40,108	40,628	41,148	41,667	42,187	42,707	43,227	43,749
115	397 Communications		467,037	468,755	470,474	472,193	473,911	475,630	479,371	483,112	486,853	490,593	494,334	499,090
116	Amortizable and Non Depreciable balance		526,462	528,303	530,144	532,023	533,907	535,786	537,644	539,485	541,326	543,167	545,008	546,858
117	<b>Total General Plant</b>		<b>1,904,608</b>	<b>1,917,651</b>	<b>1,930,693</b>	<b>1,943,773</b>	<b>1,956,858</b>	<b>1,969,938</b>	<b>1,985,018</b>	<b>2,000,083</b>	<b>2,015,147</b>	<b>2,030,211</b>	<b>2,045,276</b>	<b>2,061,409</b>
118	390 Structures													
119	Proposed Monthly Depreciation Rates	1.759%	664	672	680	688	696	704	712	720	728	736	744	752
120	392 Transportation Equipment*													
121	Proposed Monthly Depreciation Rates	4.316%	1,480	1,492	1,505	1,517	1,530	1,542	1,555	1,567	1,580	1,592	1,605	1,617
122	396 Power Operated Equipment*													
123	Proposed Monthly Depreciation Rates	11.269%	352	357	362	367	372	377	382	386	391	396	401	406
124	397 Communications													
125	Proposed Monthly Depreciation Rates	2.715%	1,055	1,057	1,061	1,064	1,068	1,072	1,076	1,085	1,093	1,102	1,110	1,118
126	Amortizable and Non Depreciable													
127	Proposed Monthly Manual Expense		1,074	1,085	1,095	1,105	1,116	1,126	1,137	1,147	1,157	1,167	1,178	1,188
128	Reclassified Transportation and Power Operated Equipment*													
129	Proposed Monthly Depreciation Rates		(1,832)	(1,849)	(1,867)	(1,884)	(1,901)	(1,919)	(1,936)	(1,954)	(1,971)	(1,988)	(2,006)	(2,023)
<b>Total General Depreciation Expense</b>														
130	2019 Proposed Annual Rates													
131	Monthly Calculated Expense		1,719	1,728	1,740	1,752	1,764	1,776	1,788	1,804	1,821	1,837	1,854	1,871
132	Manual Monthly Expense		1,974	1,085	1,095	1,105	1,116	1,126	1,137	1,147	1,157	1,167	1,178	1,188
133	<b>Total Monthly Expense</b>		<b>2,793</b>	<b>2,813</b>	<b>2,835</b>	<b>2,858</b>	<b>2,880</b>	<b>2,902</b>	<b>2,925</b>	<b>2,951</b>	<b>2,978</b>	<b>3,005</b>	<b>3,032</b>	<b>3,058</b>
<b>Total Company Depreciation Expense</b>														
134	2019 Proposed Annual Rates													
135	Monthly Calculated Expense		88,074	88,206	88,425	88,976	89,266	89,423	89,816	90,061	90,280	90,776	91,014	97,982
136	Manual Monthly Expense		7,796	7,806	7,816	7,826	7,837	7,847	7,858	7,868	7,878	7,888	7,898	7,909
137	<b>Total Monthly Expense</b>		<b>95,870</b>	<b>96,012</b>	<b>96,241</b>	<b>96,802</b>	<b>97,103</b>	<b>97,270</b>	<b>97,673</b>	<b>97,929</b>	<b>98,158</b>	<b>98,664</b>	<b>98,912</b>	<b>105,891</b>
138	<b>Total Annual Depreciation Expense</b>													
													<b>Calendar Year 2021</b>	<b>1,176,526</b>

Notes and Source:  
Per the attachment provided in the Company's response to STF-L&A-2-3 and STF-L&A-2-4

Georgia Power Company  
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Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Depr. Rate	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
		(A)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)
Steam Production- FERC's 310-312 & 314-316														
1	Bowen 1-4		4,913,181	4,926,275	4,939,389	4,952,453	4,965,455	4,965,573	4,966,753	4,967,750	4,973,667	4,975,023	4,981,248	4,999,149
2	Scherer 1-3		1,538,610	1,538,394	1,538,096	1,537,799	1,537,501	1,537,204	1,536,906	1,536,602	1,536,312	1,536,222	1,535,932	1,541,702
3	Wansley 1-2		1,038,143	1,038,151	1,038,159	1,038,167	1,038,242	1,038,469	1,038,544	1,038,619	1,038,694	1,038,769	1,038,895	1,041,168
4	Yates 6-7		347,589	347,902	347,822	348,623	349,437	350,674	350,987	351,300	351,613	352,232	352,572	352,912
5	McIntosh 1		120	120	120	120	120	120	120	120	120	120	120	120
6	Total Depreciable balance		7,837,642	7,850,842	7,863,587	7,877,162	7,890,756	7,892,040	7,893,310	7,894,591	7,900,605	7,902,366	7,908,766	7,935,651
7	Total Non Depreciable balance		2,295,713	2,295,713	2,295,713	2,295,713	2,295,713	2,297,490	2,297,490	2,297,490	2,297,490	2,297,490	2,297,490	2,300,214
8	Total Steam		10,133,355	10,146,555	10,159,300	10,172,874	10,186,469	10,189,530	10,190,800	10,192,081	10,198,095	10,199,856	10,206,256	10,235,865
Total Steam Depreciation Expense														
9	2019 Proposed Annual Rate	4.449%												
10	Monthly Calculated Expense		28,978	28,978	29,027	29,074	29,124	29,174	29,179	29,184	29,189	29,211	29,218	29,241
11	Manual Monthly Expense		5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297
12	Total Monthly Expense		34,275	34,274	34,323	34,370	34,421	34,471	34,476	34,481	34,485	34,508	34,514	34,538
Nuclear Production- FERC's 320-325														
13	Hatch 1-2		1,339,184	1,343,521	1,345,518	1,346,420	1,347,923	1,349,441	1,350,972	1,352,525	1,353,510	1,355,169	1,356,691	1,362,431
Total Hatch Depreciation Expense														
14	2019 Proposed Annual Rate	3.046%												
15	Monthly Calculated Expense		3,396	3,399	3,410	3,415	3,418	3,421	3,425	3,429	3,433	3,436	3,440	3,444
16	Manual Monthly Expense		-	-	-	-	-	-	-	-	-	-	-	-
17	Total Monthly Expense		3,396	3,399	3,410	3,415	3,418	3,421	3,425	3,429	3,433	3,436	3,440	3,444
18	Vogtle 1&2 Common		888,020	888,475	888,930	890,121	890,577	891,032	891,488	891,944	892,400	892,856	893,312	896,380
19	Vogtle 1		1,606,575	1,606,867	1,607,159	1,607,442	1,609,736	1,609,628	1,609,919	1,610,211	1,610,503	1,610,794	1,611,707	1,617,000
20	Total Depreciable balance		2,494,595	2,495,342	2,496,089	2,497,572	2,498,319	2,500,368	2,501,115	2,501,863	2,502,611	2,503,358	2,504,106	2,508,087
Total Vogtle 1&2 Comm. Unit 1 Depreciation Expense														
21	2019 Proposed Annual Rate	1.499%												
22	Monthly Calculated Expense		3,117	3,116	3,117	3,118	3,120	3,121	3,123	3,124	3,125	3,126	3,127	3,128
23	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
24	Total Monthly Expense		3,920	3,919	3,920	3,921	3,923	3,924	3,926	3,927	3,928	3,929	3,930	3,931
25	Vogtle 2		1,074,565	1,075,381	1,076,488	1,077,307	1,078,133	1,078,955	1,080,926	1,081,752	1,082,683	1,083,563	1,083,288	1,085,236
Total Vogtle Unit 2 Depreciation Expense														
26	2019 Proposed Annual Rate - 2.005%	2.005%												
27	Monthly Calculated Expense		1,794	1,795	1,797	1,799	1,800	1,801	1,803	1,806	1,807	1,809	1,810	1,810
28	Vogtle 3&4		4,585,139	4,585,498	4,585,797	4,586,071	4,586,738	4,587,415	4,588,111	4,589,070	4,590,219	4,591,339	4,592,724	4,597,343
Total Vogtle Unit 3&4 Depreciation Expense														
29	2019 Proposed Annual Rate	1.768%												
30	Monthly Calculated Expense		6,755	6,755	6,756	6,756	6,757	6,758	6,759	6,760	6,761	6,763	6,765	11,154
31	Total Non Depreciable balance		299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321
32	Total Nuclear Production		9,792,805	9,799,064	9,803,213	9,806,691	9,810,433	9,815,500	9,820,447	9,824,531	9,828,344	9,832,751	12,814,131	12,827,418
Total Nuclear Depreciation Expense														
33	2019 Proposed Annual Rate													
34	Monthly Calculated Expense		15,062	15,066	15,080	15,088	15,094	15,101	15,110	15,119	15,127	15,134	15,142	19,536
35	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
36	Total Monthly Expense		15,865	15,869	15,883	15,891	15,897	15,904	15,913	15,922	15,930	15,937	15,945	20,339
Hydro Production- FERC's 330-336														
37	Bartlett Ferry		133,923	133,937	133,951	133,965	133,978	133,992	134,006	134,020	134,034	134,048	134,062	134,062
38	Barton		13,292	13,299	13,305	13,312	13,319	13,326	13,332	13,339	13,346	13,352	13,359	13,359
39	Central Ga Hqs		367	374	381	387	394	401	408	414	421	428	434	435
40	Flint River		34,684	35,625	36,566	37,507	38,448	39,388	40,329	41,245	42,161	43,077	44,018	45,263
41	Guat Rock		94,680	101,398	108,117	114,835	121,553	128,271	134,989	141,708	148,426	155,144	161,862	166,321
42	Lloyd Shoals		27,691	27,701	27,712	27,722	27,733	27,743	27,754	27,764	27,775	27,785	27,796	27,796
43	Morgan Falls		12,196	12,227	12,258	12,290	12,321	12,353	12,384	12,415	12,447	12,558	12,590	12,621
44	Nacoochee		8,185	8,192	8,199	8,206	8,212	8,219	8,226	8,232	8,239	8,246	8,253	8,253
45	North Highlands		22,476	24,902	27,328	29,755	32,181	34,607	37,034	39,460	41,886	44,313	46,739	51,910
46	Oliver Dam		28,674	31,087	33,500	35,913	38,326	40,738	43,151	45,564	47,977	50,390	52,803	55,221
47	Savannah Dam		58,223	59,622	59,021	59,420	59,819	60,219	60,618	61,017	61,416	61,815	62,214	64,624
48	Tallulah Falls		30,372	30,379	30,387	30,394	30,401	30,408	30,415	30,422	30,429	30,437	30,444	30,444
49	Terraona		19,495	19,502	19,510	19,517	19,524	19,531	19,538	19,545	19,552	19,560	19,567	19,567
50	Tagalo		55,045	56,433	57,862	59,270	60,678	62,086	63,494	64,902	66,310	67,718	69,126	65,627
51	Wallace Dam		231,070	234,477	237,884	241,291	244,697	248,104	251,511	254,917	258,324	261,731	265,138	268,541
52	Yonah		10,170	10,424	10,677	10,931	11,184	11,438	11,692	11,945	12,199	12,452	12,706	12,954
53	Rocky Mountain 1-3		179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597
54	Total Depreciable balance		960,141	978,197	996,253	1,014,309	1,032,365	1,050,422	1,068,478	1,086,699	1,104,740	1,122,951	1,141,007	1,169,218
55	Total Non Depreciable balance		40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008
56	Total Hydro Production		1,000,149	1,018,205	1,036,262	1,054,318	1,072,374	1,090,430	1,108,486	1,126,617	1,144,748	1,162,960	1,181,016	1,179,227
Total Hydro Depreciation Expense														
57	2019 Proposed Annual Rate	2.529%												
58	Monthly Calculated Expense		1,837	2,023	2,062	2,100	2,138	2,176	2,214	2,252	2,290	2,328	2,367	2,405
59	Manual Monthly Expense		17	17	17	17	17	17	17	17	17	17	17	17
60	Total Monthly Expense		1,854	2,040	2,078	2,116	2,154	2,192	2,231	2,269	2,307	2,345	2,383	2,421
Other Production- FERC's 340-346														
61	Bondedown CT		1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
62	Community Solar		3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143
63	Dalton Solar		12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553
64	Falkon Solar		3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379
65	Fort Benning Solar		65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636
66	Fort Gordon Solar		65,643	65,643	65,643	65,643	65,643	65,643	65,643	65,643	65,643	65,643	65,643	65,643
67	Fort Stewart Solar		66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652
68	Kings Bay Solar		66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956
69	Marine Corps - Albany Solar		436,318	436,318	436,318	436,318	436,318	436,318	502,911	502,911	502,911	502,911	502,911	502,911
70	McIntosh CC		13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084
71	McIntosh CC CTs		725,461	725,518	726,241	727,495	731,245	731,245	731,358	731,414	731,471	731,647	731,703	730,701
72	McIntosh CTs		228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,024
73	Memphis CT		61,524	61,540	61,557	62,705	62,721	62,738	62,755	62,771	63,085	63,102	63,118	63,135
74	Tr 1	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801
75	University of Georgia Solar		4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569
76	Wansley CT		7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369
77	Wilson CT		46,073	46,099	46,099	47,299	47,299	47,299	47,299	47,299	47,299	47,299	47,299	47,299
78	Wilson CT		42,568	42,4										

Exhibit \_\_ (RS/RT-2)  
Schedule F-1  
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Retail Electric Amounts  
(Thousands of Dollars)

Calendar Year 2022	1,303,062
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Notes and Source:  
Per the attachment provided in the Company's response to STF-L&A-2-3 and STF-L&A-2-4

Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Dep. Rate	Dec-19 (A)	Jan-20 (B)	Feb-20 (C)	Mar-20 (D)	Apr-20 (E)	May-20 (F)	Jun-20 (G)	Jul-20 (H)	Aug-20 (I)	Sep-20 (J)	Oct-20 (K)	Nov-20 (L)	Dec-20 (M)
Stream Production- FERCs 310-312 & 314-316															
1	Bowen 1-4		4,781,234	4,731,331	4,712,248	4,730,420	4,759,405	4,927,924	4,807,588	4,888,401	4,811,376	4,813,631	4,831,740	4,817,020	4,879,833
2	Schantz 1-3		1,534,325	1,523,909	1,523,511	1,523,121	1,523,313	1,523,333	1,521,969	1,521,994	1,521,994	1,521,994	1,520,949	1,519,944	1,520,936
3	Wansley 1-2		1,026,671	1,026,875	1,027,473	1,027,686	1,028,731	1,028,773	1,029,254	1,029,734	1,030,214	1,030,694	1,031,580	1,032,639	1,035,577
4	Yates 6-7		344,431	344,509	344,587	344,666	344,839	345,015	345,624	345,718	345,812	345,905	345,998	346,090	346,121
5	McDonoh 1-3		120	120	120	120	120	120	120	120	120	120	120	120	120
6	Total Depreciable balance		7,676,780	7,626,744	7,607,938	7,626,194	7,655,356	7,824,156	7,704,566	7,765,537	7,708,681	7,711,105	7,729,716	7,715,784	7,782,587
7	Total Non Depreciable balance		2,389,721	2,290,053	2,290,385	2,290,717	2,291,051	2,291,126	2,291,201	2,291,276	2,291,351	2,291,426	2,293,355	2,293,430	2,293,505
8	Total Stream		9,966,501	9,916,797	9,938,322	9,916,911	9,946,406	10,115,281	9,995,766	9,996,813	10,000,031	10,002,530	10,023,070	10,009,213	10,076,092
Total Steam Depreciation Expense															
9	2019 Proposed Annual Rate	3.077%													
10	Monthly Calculated Expense		19,629	19,501	19,452	19,499	19,574	20,007	19,700	19,703	19,711	19,717	19,717	19,765	19,729
11	Manual Monthly Expense		5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297
12	Total Monthly Expense		24,925	24,797	24,749	24,796	24,871	25,303	24,997	24,999	25,007	25,013	25,061	25,061	25,025
Nuclear Production- FERCs 320-325															
13	Hatch 1-2		1,270,616	1,271,834	1,274,269	1,274,879	1,270,858	1,272,098	1,272,952	1,275,415	1,276,680	1,277,773	1,282,446	1,283,283	1,292,442
Total Hatch Depreciation Expense															
14	2019 Proposed Annual Rate	3.046%													
15	Monthly Calculated Expense		3,225	3,228	3,228	3,235	3,236	3,226	3,229	3,231	3,237	3,241	3,243	3,255	3,257
16	Manual Monthly Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Monthly Expense		3,225	3,228	3,228	3,235	3,236	3,226	3,229	3,231	3,237	3,241	3,243	3,255	3,257
18	Vogtle 1&2 Common		862,021	862,234	862,682	863,418	863,358	863,897	865,857	866,741	867,238	867,702	868,153	868,403	869,410
19	Vogtle 1		1,598,086	1,598,087	1,598,363	1,598,640	1,598,807	1,599,065	1,599,279	1,599,494	1,599,709	1,600,440	1,600,366	1,601,717	
20	Total Depreciable balance		2,460,107	2,460,321	2,461,045	2,462,058	2,461,901	2,462,706	2,464,922	2,466,020	2,466,732	2,467,411	2,468,302	2,468,770	2,471,127
Total Vogtle 1&2 Comm. Unit 1 Depreciation Expense															
21	2019 Proposed Annual Rate	1.499%													
22	Monthly Calculated Expense		3,073	3,073	3,074	3,074	3,076	3,076	3,079	3,080	3,081	3,082	3,083	3,083	3,084
23	Manual Monthly Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Monthly Expense		3,073	3,073	3,074	3,074	3,076	3,076	3,079	3,080	3,081	3,082	3,083	3,083	3,084
25	Vogtle 2		1,053,179	1,053,905	1,054,634	1,056,248	1,057,145	1,058,043	1,058,400	1,059,347	1,060,470	1,061,563	1,062,497	1,063,463	1,065,406
Total Vogtle Unit 2 Depreciation Expense															
26	2019 Proposed Annual Rate - 2.005%	2.005%													
27	Monthly Calculated Expense		1,760	1,761	1,762	1,765	1,766	1,768	1,768	1,770	1,772	1,774	1,775	1,777	1,777
28	Vogtle 3&4		30,257	30,257	30,257	30,257	30,257	30,257	30,303	30,303	30,303	30,304	30,304	30,350	30,350
Total Vogtle Unit 3&4 Depreciation Expense															
29	2019 Proposed Annual Rate	1.768%													
30	Monthly Calculated Expense		45	45	45	45	45	45	45	45	45	45	45	45	45
31	Total Non Depreciable balance		299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321
32	Total Nuclear Production		5,113,481	5,115,639	5,119,527	5,122,763	5,119,482	5,122,426	5,125,899	5,130,407	5,133,506	5,136,372	5,142,870	5,145,187	5,158,647
Total Nuclear Depreciation Expense															
33	2019 Proposed Annual Rate														
34	Monthly Calculated Expense		8,103	8,107	8,115	8,118	8,121	8,112	8,118	8,123	8,133	8,139	8,144	8,158	8,163
35	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803	803
36	Total Monthly Expense		8,906	8,910	8,918	8,924	8,915	8,921	8,926	8,936	8,941	8,947	8,951	8,961	8,966
Hydro Production- FERCs 330-336															
37	Bartlett Ferry		133,617	133,630	133,644	133,657	133,670	133,683	133,696	133,709	133,722	133,735	133,748	133,761	133,761
38	Barton		12,940	12,946	12,952	12,959	12,965	12,971	12,978	12,984	12,990	12,997	13,003	13,009	13,015
39	Central Gu Hps		219	225	232	244	253	264	275	286	297	308	319	329	339
40	Fine River		21,734	21,783	22,012	22,123	22,193	22,459	22,568	22,707	22,917	23,126	23,336	23,545	23,754
41	Goat Rock		31,418	31,376	33,734	34,893	37,110	38,178	39,356	40,494	41,653	42,841	43,969	45,127	46,317
42	Lloyd Shoals		27,459	27,469	27,479	27,489	27,499	27,509	27,519	27,529	27,539	27,548	27,558	27,568	27,568
43	McDonoh Falls		11,350	11,361	11,397	11,417	11,443	11,429	11,444	11,460	11,476	11,491	11,583	11,599	11,615
44	Nacoochee		7,764	7,771	7,777	7,780	7,790	7,796	7,802	7,809	7,815	7,821	7,828	7,834	7,834
45	North Highlands		14,394	14,396	14,402	14,409	14,416	14,508	14,599	14,556	14,563	14,570	14,576	14,583	14,583
46	Oliver Dam		20,607	20,613	20,620	20,627	20,633	20,725	20,817	20,774	20,780	20,787	20,794	20,801	20,801
47	Simsboro Dam		23,991	23,994	26,078	27,122	28,166	29,210	30,254	31,297	32,341	33,385	34,429	35,473	36,517
48	Tallahas Falls		30,215	30,222	30,228	30,235	30,242	30,249	30,255	30,262	30,269	30,275	30,282	30,289	30,290
49	Terora		18,245	18,252	18,258	18,265	18,272	18,279	18,285	18,292	18,299	18,305	18,312	18,319	18,319
50	Timber Lake		23,463	24,412	25,361	26,310	27,259	28,208	29,157	30,106	31,134	32,162	33,190	34,264	35,022
51	Wallace Dam		198,933	199,346	199,759	200,173	200,586	200,999	201,412	201,826	202,239	202,652	203,066	203,479	203,874
52	Yonah		9,766	9,773	9,779	9,786	9,793	9,800	9,806	9,813	9,820	9,827	9,833	9,840	9,840
53	Rocky Mountain 1-3		179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597
54	Total Depreciable balance		765,787	765,581	773,206	777,090	781,344	785,819	789,783	793,478	797,423	802,128	806,613	809,886	817,835
55	Total Non Depreciable balance		40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008
56	Total Hydro Production		805,715	809,510	813,304	817,099	821,952	825,827	829,792	833,486	837,431	842,129	846,622	849,816	827,844
Total Hydro Depreciation Expense															
57	2019 Proposed Annual Rate	2.529%													
58	Monthly Calculated Expense		1,614	1,622	1,630	1,638	1,648	1,656	1,664	1,672	1,681	1,690	1,699	1,707	1,707
59	Manual Monthly Expense		17	17	17	17	17	17	17	17	17	17	17	17	17
60	Total Monthly Expense		1,630	1,638	1,646	1,654	1,665	1,673	1,681	1,689	1,697	1,707	1,715	1,723	1,723
Other Production- FERCs 340-346															
61	Bowlesville CT		1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
62	Community Solar		3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143
63	Dalton Solar		12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553
64	Falcous Solar		3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379
65	Fort Benning Solar		65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636
66	Fort Gordon Solar		65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443
67	Fort Stewart Solar		66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652
68	Kings Bay Solar		66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956
69	Marine Corps - Albany Solar		81,083	87,072	87,072	164,530	171,157	187,084	187,084	187,084	187,084	187,084	187,089	187,089	187,089
70	McDonough CT		13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084
71	McDonough CC CTs		664,854	666,298	708,682	712,944	715,949	718,727	719,205	719,274	719,344	719,413	720,055	720,612	720,678
72	McDonoh CTs		225,616	225,688	225,688	225,748	225,771	225,771	225,771	225,771	225,921	226,219	226,357	226,682	227,014
73	Memana CT		60,543	60,560	60,576	60,593	60,687	60,903	60,920	60,937	60,953	60,970	60,987	61,003	61,020
74	Northview Solar		1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801
75	University of Georgia Solar		4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569
76	Wansley CT														

Georgia Power Company  
Depreciation Expense  
Per Staff  
Calendar Year 2020

Exhibit (RS/RT-2)  
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Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Depr. Rate (A)	Dec-19 (B)	Jan-20 (C)	Feb-20 (D)	Mar-20 (E)	Apr-20 (F)	May-20 (G)	Jun-20 (H)	Jul-20 (I)	Aug-20 (J)	Sep-20 (K)	Oct-20 (L)	Nov-20 (M)	Dec-20 (N)
<b>Transmission Plant- FERC's 350-359</b>															
91	Total Depreciable balance		6,056,860	6,170,503	6,207,836	6,223,909	6,235,694	6,252,146	6,330,941	6,281,608	6,301,979	6,346,951	6,390,665	6,422,112	6,461,104
92	Non Depreciable balance		426,241	426,292	427,469	427,520	427,572	427,624	427,676	427,879	428,032	428,186	428,340	428,494	428,798
93	Total Transmission Plant		<b>6,483,101</b>	<b>6,596,795</b>	<b>6,635,305</b>	<b>6,651,430</b>	<b>6,663,266</b>	<b>6,679,770</b>	<b>6,758,617</b>	<b>6,709,487</b>	<b>6,730,012</b>	<b>6,775,137</b>	<b>6,819,004</b>	<b>6,850,605</b>	<b>6,889,902</b>
<b>Transmission Depreciation Expense</b>															
94	2019 Proposed Annual Rate	2.196%													
95	Monthly Calculated Expense			11,072	11,290	11,349	11,378	11,400	11,430	11,574	11,484	11,521	11,603	11,683	11,741
96	Manual Monthly Expense			450	450	450	450	450	450	450	450	450	450	450	450
97	Total Monthly Expense			11,522	11,730	11,798	11,828	11,849	11,879	12,023	11,933	11,970	12,053	12,133	12,190
<b>Distribution Plant- FERC's 360-362 &amp; 364-373</b>															
98	Total Depreciable balance		10,337,286	10,366,894	10,396,377	10,468,482	10,511,839	10,536,136	10,610,415	10,662,304	10,711,405	10,814,619	10,862,736	10,911,698	11,020,347
99	Non Depreciable balance		160,790	160,790	160,790	160,790	160,790	160,790	160,790	160,990	160,990	160,990	160,990	160,990	161,780
100	Total Distribution Plant		<b>10,498,075</b>	<b>10,527,684</b>	<b>10,557,167</b>	<b>10,629,271</b>	<b>10,672,628</b>	<b>10,696,925</b>	<b>10,771,204</b>	<b>10,823,294</b>	<b>10,872,395</b>	<b>10,975,608</b>	<b>11,023,726</b>	<b>11,072,687</b>	<b>11,182,086</b>
<b>Distribution Depreciation Expense</b>															
101	2019 Proposed Annual Rate	2.7%													
102	Monthly Calculated Expense			23,259	23,325	23,392	23,554	23,651	23,706	23,873	23,990	24,100	24,333	24,441	24,551
103	Manual Monthly Expense			153	153	153	153	153	153	153	153	153	153	153	153
104	Total Monthly Expense			23,412	23,479	23,545	23,707	23,805	23,859	24,027	24,143	24,254	24,486	24,594	24,704
105	Total GPC Unregulated ODI Depreciable balance		<b>543,575</b>	<b>549,676</b>	<b>555,758</b>	<b>562,407</b>	<b>570,044</b>	<b>577,702</b>	<b>585,908</b>	<b>594,082</b>	<b>602,745</b>	<b>610,926</b>	<b>620,073</b>	<b>628,721</b>	<b>637,393</b>
<b>Distribution - Unregulated ODI</b>															
106	2019 Proposed Annual Rate	3.47%													
107	Monthly Calculated Expense			1,572	1,589	1,607	1,626	1,648	1,671	1,694	1,718	1,743	1,767	1,793	1,818
<b>Total Distribution Depreciation Expense</b>															
108	2019 Proposed Annual Rates														
109	Monthly Calculated Expense			24,830	24,915	24,999	25,180	25,300	25,377	25,567	25,708	25,843	26,099	26,234	26,369
110	Manual Monthly Expense			152	152	152	152	152	152	152	152	152	152	152	152
111	Total Monthly Expense			24,983	25,067	25,151	25,332	25,452	25,529	25,719	25,860	25,995	26,251	26,386	26,521
<b>General Plant- FERC's 380, 390, 392.1-4, 396, &amp; 397</b>															
<b>General Plant Balances</b>															
112	390 Structures		362,087	366,689	371,291	375,894	419,671	424,273	428,875	429,712	434,314	438,916	443,518	448,120	452,744
113	392 Transportation Equipment		370,136	373,571	377,007	380,442	383,877	387,312	390,747	394,182	397,617	401,052	404,488	407,923	411,374
114	396 Power Operated Equipment		31,347	31,860	32,374	32,887	33,400	33,913	34,427	34,940	35,453	35,967	36,480	36,993	37,509
115	397 Communications		423,945	426,666	429,314	431,963	434,611	437,260	439,908	444,419	448,929	453,440	457,951	462,461	466,260
116	Amortizable and Non Depreciable balance		437,589	427,789	429,662	431,530	515,584	517,664	519,742	521,784	523,819	525,859	527,898	529,938	531,987
117	Total General Plant		<b>1,625,105</b>	<b>1,628,575</b>	<b>1,639,647</b>	<b>1,652,715</b>	<b>1,787,143</b>	<b>1,800,422</b>	<b>1,813,698</b>	<b>1,825,037</b>	<b>1,840,133</b>	<b>1,855,234</b>	<b>1,870,334</b>	<b>1,885,435</b>	<b>1,899,875</b>
118	390 Structures														
119	Proposed Monthly Depreciation Rates	1.759%		531	538	544	551	615	622	629	630	637	643	650	657
120	392 Transportation Equipment*														
121	Proposed Monthly Depreciation Rates	4.316%		1,331	1,344	1,356	1,368	1,381	1,393	1,405	1,418	1,430	1,442	1,455	1,467
122	396 Power Operated Equipment*														
123	Proposed Monthly Depreciation Rates	11.269%		294	299	304	309	314	318	323	328	333	338	343	347
124	397 Communications														
125	Proposed Monthly Depreciation Rates	2.715%		959	965	971	977	983	989	995	1,005	1,016	1,026	1,036	1,046
126	Amortizable and Non Depreciable														
127	Proposed Monthly Manual Expense			1,665	1,680	1,695	1,710	1,726	1,741	1,756	1,771	1,786	1,801	1,096	1,106
128	Reclassified Transportation and Power Operated Equipment*														
129	Proposed Monthly Depreciation Rates			(1,626)	(1,643)	(1,660)	(1,677)	(1,694)	(1,712)	(1,729)	(1,746)	(1,763)	(1,780)	(1,797)	(1,815)
<b>Total General Depreciation Expense</b>															
130	2019 Proposed Annual Rates														
131	Monthly Calculated Expense			1,490	1,503	1,516	1,528	1,598	1,611	1,624	1,635	1,652	1,669	1,686	1,703
132	Manual Monthly Expense			1,665	1,680	1,695	1,710	1,726	1,741	1,756	1,771	1,786	1,801	1,096	1,106
133	Total Monthly Expense			3,155	3,183	3,211	3,239	3,324	3,352	3,380	3,406	3,438	3,470	2,782	2,810
<b>Total Company Depreciation Expense</b>															
134	2019 Proposed Annual Rates														
135	Monthly Calculated Expense			74,878	75,090	75,338	75,876	76,197	76,816	76,875	76,960	77,174	77,680	77,911	78,105
136	Manual Monthly Expense			8,387	8,402	8,417	8,432	8,447	8,462	8,477	8,492	8,507	8,522	7,817	7,827
137	Total Monthly Expense			<b>83,265</b>	<b>83,491</b>	<b>83,755</b>	<b>84,307</b>	<b>84,644</b>	<b>85,278</b>	<b>85,353</b>	<b>85,452</b>	<b>85,682</b>	<b>86,202</b>	<b>85,728</b>	<b>85,932</b>
138	Total Annual Depreciation Expense													<b>Calendar Year 2020</b>	<b>1,019,089</b>

Notes and Source:

Per the attachment provided in the Company's response to STF-L&A-2-3 and STF-L&A-2-4  
Col A: Per the recommended depreciation rates by Staff witness William Daniel



Retail Electric Amount  
(Thousands of Dollars)

Line No.	Description	Depr. Rate	Jan-21 (A)	Feb-21 (B)	Mar-21 (C)	Apr-21 (D)	May-21 (E)	Jun-21 (F)	Jul-21 (G)	Aug-21 (H)	Sep-21 (I)	Oct-21 (J)	Nov-21 (K)	Dec-21 (L)
<b>Stream Production- FERC's 310-312 &amp; 314-316</b>														
1	Bowen 1-4		4,857,047	4,852,822	4,872,338	4,890,798	4,887,257	4,883,084	4,880,374	4,878,446	4,886,186	4,892,439	4,899,754	4,913,336
2	Schenck 1-3		1,520,827	1,520,717	1,520,608	1,530,836	1,530,825	1,531,594	1,531,594	1,531,558	1,531,506	1,531,454	1,531,402	1,538,807
3	Wansley 1-2		1,035,607	1,035,636	1,035,665	1,035,694	1,035,791	1,035,887	1,036,079	1,036,175	1,036,175	1,036,271	1,036,367	1,038,135
4	Yates 6-7		346,198	346,275	346,411	346,630	346,853	346,914	346,974	347,034	347,095	347,155	347,215	347,276
5	Micklin 1-2		120	120	120	120	120	120	120	120	120	120	120	120
6	Total Depreciable balance		7,585,799	7,555,571	7,575,189	7,603,078	7,600,846	7,597,598	7,595,073	7,593,237	7,601,082	7,607,439	7,614,860	7,637,774
7	Total Non Depreciable balance		2,293,506	2,293,688	2,293,780	2,293,871	2,293,963	2,294,055	2,294,146	2,294,238	2,294,330	2,294,421	2,295,521	2,295,713
8	Total Stream		10,853,395	10,849,259	10,868,969	10,896,949	10,893,809	10,891,652	10,889,219	10,887,475	10,895,412	10,901,860	10,910,380	10,933,487
<b>Total Stream Depreciation Expense</b>														
9	2019 Proposed Annual Rate	3.077%												
10	Monthly Calculated Expense		19,900	19,842	19,831	19,881	19,953	19,947	19,939	19,932	19,927	19,948	19,964	19,983
11	Manual Monthly Expense		5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297
12	Total Monthly Expense		25,197	25,138	25,127	25,178	25,249	25,244	25,235	25,229	25,224	25,244	25,260	25,280
<b>Nuclear Production- FERC's 320-325</b>														
13	Hatch 1-2		1,294,308	1,297,786	1,298,655	1,313,811	1,315,747	1,322,597	1,324,625	1,326,627	1,330,689	1,332,934	1,335,066	1,337,972
<b>Total Hatch Depreciation Expense</b>														
14	2019 Proposed Annual Rate	3.046%												
15	Monthly Calculated Expense		3,281	3,285	3,294	3,296	3,335	3,340	3,357	3,362	3,367	3,378	3,383	3,389
16	Manual Monthly Expense		-	-	-	-	-	-	-	-	-	-	-	-
17	Total Monthly Expense		3,281	3,285	3,294	3,296	3,335	3,340	3,357	3,362	3,367	3,378	3,383	3,389
18	Vogtle 1&2 Comm		870,882	870,763	871,443	872,123	872,795	873,460	874,125	874,791	876,672	877,337	886,696	888,126
19	Vogtle 1		1,602,488	1,603,114	1,603,732	1,604,291	1,604,855	1,605,417	1,605,979	1,606,542	1,607,105	1,607,621	1,606,591	1,605,103
20	Total Depreciable balance		2,472,571	2,473,877	2,475,175	2,476,416	2,477,650	2,478,877	2,480,105	2,481,333	2,483,777	2,484,958	2,493,287	2,497,237
<b>Total Vogtle 1&amp;2 Comm, Unit 1 Depreciation Expense</b>														
21	2019 Proposed Annual Rate	1.499%												
22	Monthly Calculated Expense		3,087	3,089	3,090	3,092	3,093	3,095	3,097	3,098	3,100	3,103	3,104	3,115
23	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
24	Total Monthly Expense		3,890	3,892	3,893	3,895	3,896	3,898	3,900	3,901	3,903	3,906	3,907	3,918
25	Vogtle 2		1,067,285	1,067,570	1,068,134	1,068,411	1,068,692	1,068,970	1,069,246	1,069,518	1,069,963	1,070,356	1,070,655	1,073,745
<b>Total Vogtle Unit 2 Depreciation Expense</b>														
26	2019 Proposed Annual Rate - 2.005%	2.005%												
27	Monthly Calculated Expense		1,780	1,783	1,784	1,785	1,785	1,786	1,786	1,787	1,787	1,788	1,788	1,789
28	Vogtle 3&4		30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350	30,350
<b>Total Vogtle Unit 3&amp;4 Depreciation Expense</b>														
29	2019 Proposed Annual Rate	1.768%												
30	Monthly Calculated Expense		45	45	45	45	45	45	45	45	45	45	45	45
31	Total Non Depreciable balance		299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321	299,321
32	Total Nuclear Production		5,163,836	5,168,994	5,171,635	5,188,130	5,191,761	5,200,116	5,203,468	5,207,150	5,214,100	5,217,019	5,283,113	5,291,054
<b>Total Nuclear Depreciation Expense</b>														
33	2019 Proposed Annual Rate													
34	Monthly Calculated Expense		8,192	8,202	8,213	8,218	8,258	8,265	8,285	8,292	8,299	8,313	8,321	15,047
35	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
36	Total Monthly Expense		8,995	9,005	9,016	9,021	9,061	9,068	9,088	9,097	9,095	9,116	9,124	15,850
<b>Hydro Production- FERC's 330-336</b>														
37	Bartlett Ferry		133,774	133,788	133,801	133,815	133,828	133,842	133,855	133,868	133,882	133,895	133,909	133,909
38	Barton		13,016	13,022	13,029	13,035	13,042	13,048	13,055	13,258	13,352	13,359	13,285	13,285
39	Central Gals Hgs		305	302	308	305	321	328	334	341	347	354	360	361
40	Flint River		24,440	25,266	26,091	26,917	27,742	28,568	29,393	30,219	31,190	32,088	32,914	33,743
41	Gust Rock		47,393	52,649	57,905	63,161	68,417	73,673	78,960	84,319	89,678	95,355	101,032	87,962
42	Lloyd Shoals		22,678	27,588	27,599	27,609	27,619	27,629	27,639	27,649	27,660	27,670	27,680	27,680
43	McIntosh Falls		11,654	11,669	11,732	11,772	11,811	11,850	11,890	11,929	11,968	12,005	12,125	12,164
44	Nacoochee		7,840	7,847	7,853	7,860	7,866	7,873	7,879	7,886	8,165	8,165	8,179	8,179
45	North Highlands		15,028	15,474	15,920	16,365	16,808	17,431	17,827	18,272	18,718	19,163	19,609	20,050
46	Oliver Dam		21,296	21,711	22,167	22,622	23,078	23,533	23,988	24,444	24,899	25,355	25,810	26,261
47	Sicular Dam		38,828	41,144	43,461	45,777	48,093	50,410	52,726	55,042	57,359	59,675	61,991	57,824
48	Talladega Falls		30,226	30,300	30,310	30,317	30,323	30,330	30,337	30,344	30,351	30,358	30,365	30,365
49	Terrora		18,326	18,333	18,340	19,440	19,446	19,453	19,460	19,467	19,474	19,481	19,488	19,488
50	Walden		36,573	38,124	39,676	41,227	42,778	44,329	45,880	47,432	48,983	50,534	52,085	53,637
51	Wallace Dam		205,858	207,841	209,824	211,808	213,791	215,774	217,758	219,741	221,724	223,707	225,691	227,664
52	Yonah		9,847	9,854	9,861	9,868	9,875	9,882	9,888	9,895	9,902	9,909	9,916	9,916
53	Rocky Mountain 1-3		179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	109,047
54	Total Depreciable balance		821,680	825,337	827,473	861,583	874,523	887,530	900,468	913,736	927,356	940,758	954,836	871,234
55	Total Non Depreciable balance		40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008	40,008
56	Total Hydro Production		861,689	875,454	887,482	901,511	914,535	927,539	940,476	953,785	967,258	980,767	994,405	911,542
<b>Total Hydro Depreciation Expense</b>														
57	2019 Proposed Annual Rate	2.529%												
58	Monthly Calculated Expense		1,659	1,732	1,759	1,786	1,816	1,843	1,871	1,898	1,926	1,954	1,983	2,011
59	Manual Monthly Expense		17	17	17	17	17	17	17	17	17	17	17	17
60	Total Monthly Expense		1,675	1,748	1,776	1,803	1,832	1,860	1,887	1,914	1,943	1,971	1,999	2,027
<b>Other Production- FERC's 340-346</b>														
61	Boulders CT		1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
62	Community Solar		3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143
63	Dallas Solar		12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553
64	Falcons Solar		3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379
65	Fort Benning Solar		65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636
66	Fort Gordon Solar		65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443
67	McIntosh Solar		66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652
68	Kings Bay Solar		66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956
69	Marine Corps - Albany Solar		406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278	406,278
70	McIntosh CC CTs		13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084
71	McIntosh CC CTs		720,737	720,737	720,737	724,724	724,724	724,724	724,612	724,612	724,612	724,725	725,292	725,405
72	McIntosh CC CTs		227,368	227,410	227,452	227,494	227,536	227,578	227,620	227,662	228,104	228,346	228,588	228,756
73	Memphis CT		61,037	61,053	61,069	61,077	61,084	61,091	61,098	61,105	61,112	61,119	61,126	61,133
74	North Highlands		1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801
75	University of Georgia Solar		4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569	4,569
76	Wansley CT		7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369	7,369
77	McIntosh CC CTs		42,399	42,420	42,441	42,461	42,482	42,502	42,523	42,543	42,564	42,584	42,605	42,625
78	Willcox CT		41,599	41,616	41,632	41,649	41,666	41,682	41,699	41,716	42,501	42,518	42,535	42,552
79	Total Depreciable balance		1,813,492	1,815,407	1,818,302	1,819,628	1,819,350	1,819,503	1,819,656	1,820,009	1,821,131	1,821,996	1,822,349	1,822,668
80	2019 Proposed Annual Rate	3.197%												

Georgia Power Company  
Depreciation Expense  
Per Staff  
Calendar Year 2021

Exhibit (RS/RT-2)  
Schedule F-1  
Page 15 of 17

Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Depr. Rate (A)	Jan-21 (O)	Feb-21 (P)	Mar-21 (Q)	Apr-21 (R)	May-21 (S)	Jun-21 (T)	Jul-21 (U)	Aug-21 (V)	Sep-21 (W)	Oct-21 (X)	Nov-21 (Y)	Dec-21 (Z)
<b>Transmission Plant- FERC's 350-359</b>														
91	<b>Total Depreciable balance</b>		6,493,419	6,531,311	6,536,683	6,550,419	6,570,876	6,585,247	6,617,429	6,639,265	6,659,048	6,673,439	6,695,940	6,721,023
92	<b>Non Depreciable balance</b>		429,183	429,235	429,787	429,840	430,094	430,147	430,303	430,460	430,616	430,773	430,931	431,239
93	<b>Total Transmission Plant</b>		<b>6,922,602</b>	<b>6,960,546</b>	<b>6,966,471</b>	<b>6,980,259</b>	<b>7,000,969</b>	<b>7,015,394</b>	<b>7,047,732</b>	<b>7,069,724</b>	<b>7,089,665</b>	<b>7,104,212</b>	<b>7,126,871</b>	<b>7,152,263</b>
<b>Transmission Depreciation Expense</b>														
94	<b>2019 Proposed Annual Rate</b>	<b>2.196%</b>												
95	Monthly Calculated Expense		11,812	11,871	11,941	11,950	11,975	12,013	12,039	12,098	12,138	12,174	12,201	12,242
96	Manual Monthly Expense		450	450	450	450	450	450	450	450	450	450	450	450
97	<b>Total Monthly Expense</b>		<b>12,262</b>	<b>12,321</b>	<b>12,390</b>	<b>12,400</b>	<b>12,425</b>	<b>12,462</b>	<b>12,489</b>	<b>12,548</b>	<b>12,588</b>	<b>12,624</b>	<b>12,650</b>	<b>12,691</b>
<b>Distribution Plant- FERC's 360-362 &amp; 364-373</b>														
98	<b>Total Depreciable balance</b>		11,040,503	11,081,862	11,210,077	11,233,016	11,257,496	11,388,683	11,442,366	11,490,200	11,634,506	11,681,823	11,727,425	11,888,060
99	<b>Non Depreciable balance</b>		161,740	162,090	162,283	162,283	162,283	162,283	162,283	162,283	162,283	162,283	162,283	162,283
100	<b>Total Distribution Plant</b>		<b>11,202,243</b>	<b>11,243,952</b>	<b>11,372,360</b>	<b>11,395,299</b>	<b>11,419,779</b>	<b>11,550,967</b>	<b>11,604,649</b>	<b>11,652,483</b>	<b>11,796,789</b>	<b>11,844,106</b>	<b>11,889,708</b>	<b>12,050,344</b>
<b>Distribution Depreciation Expense</b>														
101	<b>2019 Proposed Annual Rate</b>	<b>2.7%</b>												
102	Monthly Calculated Expense		24,796	24,841	24,934	25,222	25,274	25,329	25,624	25,745	25,853	26,177	26,284	26,386
103	Manual Monthly Expense		153	153	153	153	153	153	153	153	153	153	153	153
104	<b>Total Monthly Expense</b>		<b>24,949</b>	<b>24,994</b>	<b>25,087</b>	<b>25,376</b>	<b>25,427</b>	<b>25,483</b>	<b>25,778</b>	<b>25,898</b>	<b>26,006</b>	<b>26,331</b>	<b>26,437</b>	<b>26,540</b>
105	<b>Total GPC Unregulated ODI Depreciable balance</b>		<b>642,966</b>	<b>648,519</b>	<b>654,656</b>	<b>661,812</b>	<b>668,987</b>	<b>676,728</b>	<b>684,436</b>	<b>692,647</b>	<b>700,361</b>	<b>709,072</b>	<b>717,268</b>	<b>725,485</b>
<b>Distribution - Unregulated ODI</b>														
106	<b>2019 Proposed Annual Rate</b>	<b>3.47%</b>												
107	Monthly Calculated Expense		1,843	1,859	1,875	1,893	1,914	1,934	1,957	1,979	2,003	2,025	2,050	2,074
108	<b>Total Distribution Depreciation Expense</b>													
109	Monthly Calculated Expense		26,639	26,700	26,809	27,115	27,188	27,264	27,581	27,724	27,856	28,203	28,334	28,461
110	Manual Monthly Expense		152	152	152	152	152	152	152	152	152	152	152	152
111	<b>Total Monthly Expense</b>		<b>26,790</b>	<b>26,852</b>	<b>26,961</b>	<b>27,267</b>	<b>27,340</b>	<b>27,415</b>	<b>27,733</b>	<b>27,876</b>	<b>28,007</b>	<b>28,354</b>	<b>28,486</b>	<b>28,612</b>
<b>General Plant- FERC's 289, 390, 392.1-4, 396, &amp; 397</b>														
<b>General Plant Balances</b>														
112	390 Structures		458,228	463,712	469,196	474,680	480,164	485,648	491,132	496,616	502,100	507,584	513,068	518,578
113	392 Transportation Equipment		414,853	418,331	421,810	425,289	428,767	432,246	435,725	439,203	442,682	446,160	449,639	453,134
114	396 Power Operated Equipment		38,029	38,549	39,068	39,588	40,108	40,628	41,148	41,667	42,187	42,707	43,227	43,749
115	397 Communications		467,037	468,755	470,474	472,193	473,911	475,630	479,371	483,112	486,853	490,593	494,334	499,090
116	<b>Amortizable and Non Depreciable balance</b>		<b>526,462</b>	<b>528,303</b>	<b>530,144</b>	<b>532,023</b>	<b>533,907</b>	<b>535,786</b>	<b>537,644</b>	<b>539,485</b>	<b>541,326</b>	<b>543,167</b>	<b>545,008</b>	<b>546,858</b>
117	<b>Total General Plant</b>		<b>1,904,608</b>	<b>1,917,651</b>	<b>1,930,693</b>	<b>1,943,773</b>	<b>1,956,858</b>	<b>1,969,938</b>	<b>1,983,018</b>	<b>2,000,083</b>	<b>2,015,147</b>	<b>2,030,211</b>	<b>2,045,276</b>	<b>2,061,409</b>
118	390 Structures													
119	Proposed Monthly Depreciation Rates	<b>1.759%</b>	664	672	680	688	696	704	712	720	728	736	744	752
120	392 Transportation Equipment*													
121	Proposed Monthly Depreciation Rates	<b>4.316%</b>	1,480	1,492	1,505	1,517	1,530	1,542	1,555	1,567	1,580	1,592	1,605	1,617
122	396 Power Operated Equipment*													
123	Proposed Monthly Depreciation Rates	<b>11.269%</b>	352	357	362	367	372	377	382	386	391	396	401	406
124	397 Communications													
125	Proposed Monthly Depreciation Rates	<b>2.715%</b>	1,055	1,057	1,061	1,064	1,068	1,072	1,076	1,085	1,093	1,102	1,110	1,118
126	Amortizable and Non Depreciable													
127	Proposed Monthly Manual Expense		1,074	1,085	1,095	1,105	1,116	1,126	1,137	1,147	1,157	1,167	1,178	1,188
128	Reclassified Transportation and Power Operated Equipment*													
129	Proposed Monthly Depreciation Rates		(1,832)	(1,849)	(1,867)	(1,884)	(1,901)	(1,919)	(1,936)	(1,954)	(1,971)	(1,988)	(2,006)	(2,023)
<b>Total General Depreciation Expense</b>														
130	<b>2019 Proposed Annual Rates</b>													
131	Monthly Calculated Expense		1,719	1,728	1,740	1,752	1,764	1,776	1,788	1,804	1,821	1,837	1,854	1,871
132	Manual Monthly Expense		1,074	1,085	1,095	1,105	1,116	1,126	1,137	1,147	1,157	1,167	1,178	1,188
133	<b>Total Monthly Expense</b>		<b>2,793</b>	<b>2,813</b>	<b>2,835</b>	<b>2,858</b>	<b>2,880</b>	<b>2,902</b>	<b>2,925</b>	<b>2,951</b>	<b>2,978</b>	<b>3,005</b>	<b>3,032</b>	<b>3,058</b>
<b>Total Company Depreciation Expense</b>														
134	<b>2019 Proposed Annual Rates</b>													
135	Monthly Calculated Expense		79,201	79,359	79,583	80,111	80,370	80,528	80,925	81,174	81,395	81,881	82,112	89,072
136	Manual Monthly Expense		7,796	7,806	7,816	7,826	7,837	7,847	7,858	7,868	7,878	7,888	7,898	7,909
137	<b>Total Monthly Expense</b>		<b>86,997</b>	<b>87,164</b>	<b>87,399</b>	<b>87,938</b>	<b>88,207</b>	<b>88,376</b>	<b>88,783</b>	<b>89,042</b>	<b>89,273</b>	<b>89,769</b>	<b>90,011</b>	<b>96,981</b>
138	<b>Total Annual Depreciation Expense</b>		<b>Calendar Year 2021</b>											<b>1,069,938</b>

Notes and Source:  
Per the attachment provided in the Company's response to ST1-L&A-2-3 and ST1-L&A-2-4  
Col A: Per the recommended depreciation rates by Staff witness William Dunkel

Georgia Power Company  
Depreciation Expense  
Per Staff  
Calendar Year 2022

Exhibit \_\_ (RS/RT-2)  
Schedule F-1  
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Retail Electric Amounts:  
(Thousands of Dollars)

Line No.	Description	Depr. Rate (A)	Jan-22 (A)	Feb-22 (A)	Mar-22 (A)	Apr-22 (A)	May-22 (A)	Jun-22 (A)	Jul-22 (A)	Aug-22 (A)	Sep-22 (A)	Oct-22 (A)	Nov-22 (A)	Dec-22 (A)
<b>Steam Production- FERCs 310-312 &amp; 314-316</b>														
1	Brown 1-4		4,913,181	4,926,275	4,939,389	4,952,483	4,965,455	4,968,573	4,966,753	4,967,750	4,973,667	4,975,023	4,981,248	4,999,149
2	Wansley 1-3		1,538,619	1,538,284	1,538,062	1,537,790	1,537,501	1,537,204	1,536,906	1,536,602	1,536,212	1,535,922	1,541,822	1,541,822
3	Wansley 1-2		1,038,143	1,038,151	1,038,159	1,038,167	1,038,242	1,038,469	1,038,544	1,038,619	1,038,694	1,038,769	1,038,895	1,041,168
4	Yates 6-7		347,589	347,902	347,822	348,023	349,437	350,674	350,987	351,300	351,613	352,322	352,572	352,912
5	McIntosh 1		120	120	120	120	120	120	120	120	120	120	120	120
6	<b>Total Depreciable balance</b>		<b>7,837,642</b>	<b>7,885,462</b>	<b>7,863,587</b>	<b>7,877,162</b>	<b>7,890,756</b>	<b>7,892,400</b>	<b>7,893,310</b>	<b>7,894,591</b>	<b>7,900,685</b>	<b>7,902,366</b>	<b>7,908,766</b>	<b>7,915,851</b>
7	<b>Total Non Depreciable balance</b>		<b>2,295,713</b>	<b>2,295,713</b>	<b>2,295,713</b>	<b>2,295,713</b>	<b>2,295,713</b>	<b>2,297,490</b>	<b>2,297,490</b>	<b>2,297,490</b>	<b>2,297,490</b>	<b>2,297,490</b>	<b>2,297,490</b>	<b>2,300,214</b>
8	<b>Total Steam</b>		<b>10,133,355</b>	<b>10,180,855</b>	<b>10,159,300</b>	<b>10,172,874</b>	<b>10,186,469</b>	<b>10,189,890</b>	<b>10,192,801</b>	<b>10,192,081</b>	<b>10,198,096</b>	<b>10,199,856</b>	<b>10,206,256</b>	<b>10,235,365</b>
<b>Total Steam Depreciation Expense</b>														
9	<b>2019 Proposed Annual Rate</b>	3.077%												
10	Monthly Calculated Expense		20,042	20,041	20,075	20,108	20,143	20,178	20,181	20,184	20,187	20,203	20,207	20,224
11	Manual Monthly Expense		5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297	5,297
12	<b>Total Monthly Expense</b>		<b>25,338</b>	<b>25,338</b>	<b>25,372</b>	<b>25,404</b>	<b>25,439</b>	<b>25,474</b>	<b>25,481</b>	<b>25,484</b>	<b>25,484</b>	<b>25,499</b>	<b>25,504</b>	<b>25,520</b>
<b>Nuclear Production- FERCs 320-325</b>														
13	Hatch 1-2		1,339,184	1,343,521	1,345,518	1,346,420	1,347,923	1,349,441	1,350,972	1,352,425	1,353,510	1,355,169	1,356,691	1,362,431
<b>Total Hatch Depreciation Expense</b>														
14	<b>2019 Proposed Annual Rate</b>	3.046%												
15	Monthly Calculated Expense		3,396	3,399	3,410	3,415	3,418	3,421	3,425	3,429	3,433	3,436	3,440	3,444
16	Manual Monthly Expense													
17	<b>Total Monthly Expense</b>		<b>3,396</b>	<b>3,399</b>	<b>3,410</b>	<b>3,415</b>	<b>3,418</b>	<b>3,421</b>	<b>3,425</b>	<b>3,429</b>	<b>3,433</b>	<b>3,436</b>	<b>3,440</b>	<b>3,444</b>
18	Vogtle 1&2 Comm		888,020	888,475	888,930	890,121	890,577	891,032	891,488	891,944	892,400	892,856	893,312	896,380
19	Vogtle 1		1,606,575	1,606,867	1,607,159	1,607,450	1,607,742	1,609,336	1,609,628	1,609,919	1,610,211	1,610,503	1,610,794	1,611,087
20	<b>Total Depreciable balance</b>		<b>2,494,595</b>	<b>2,495,342</b>	<b>2,496,089</b>	<b>2,497,572</b>	<b>2,498,319</b>	<b>2,500,368</b>	<b>2,501,115</b>	<b>2,501,863</b>	<b>2,502,611</b>	<b>2,503,358</b>	<b>2,504,106</b>	<b>2,508,087</b>
<b>Total Vogtle 1&amp;2 Comm. Unit 1 Depreciation Expense</b>														
21	<b>2019 Proposed Annual Rate</b>	1.499%												
22	Monthly Calculated Expense		3,117	3,116	3,117	3,118	3,120	3,121	3,123	3,124	3,125	3,126	3,127	3,128
23	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
24	<b>Total Monthly Expense</b>		<b>3,920</b>	<b>3,919</b>	<b>3,920</b>	<b>3,921</b>	<b>3,923</b>	<b>3,924</b>	<b>3,926</b>	<b>3,927</b>	<b>3,928</b>	<b>3,929</b>	<b>3,930</b>	<b>3,931</b>
25	Vogtle 2		1,074,565	1,075,381	1,076,488	1,077,307	1,078,133	1,078,955	1,080,926	1,081,752	1,082,683	1,083,563	1,083,288	1,085,236
<b>Total Vogtle Unit 2 Depreciation Expense</b>														
26	<b>2019 Proposed Annual Rate - 2.005%</b>	2.005%												
27	Monthly Calculated Expense		1,794	1,795	1,797	1,799	1,800	1,801	1,803	1,806	1,807	1,809	1,810	1,810
28	Vogtle 3&4		4,585,139	4,585,498	4,585,797	4,586,071	4,586,738	4,587,415	4,588,111	4,589,070	4,590,219	4,591,339	4,591,724	4,592,343
<b>Total Vogtle Unit 1&amp;4 Depreciation Expense</b>														
29	<b>2019 Proposed Annual Rate</b>	1.768%												
30	Monthly Calculated Expense		6,755	6,755	6,756	6,756	6,757	6,758	6,759	6,760	6,761	6,763	6,765	11,154
31	<b>Total Non Depreciable balance</b>		<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>	<b>299,321</b>
32	<b>Total Nuclear Production</b>		<b>9,792,805</b>	<b>9,799,064</b>	<b>9,803,213</b>	<b>9,806,691</b>	<b>9,810,433</b>	<b>9,815,500</b>	<b>9,820,447</b>	<b>9,824,531</b>	<b>9,828,244</b>	<b>9,832,571</b>	<b>12,814,131</b>	<b>12,827,418</b>
<b>Total Nuclear Depreciation Expense</b>														
33	<b>2019 Proposed Annual Rate</b>													
34	Monthly Calculated Expense		15,062	15,066	15,080	15,088	15,094	15,101	15,110	15,119	15,127	15,134	15,142	19,536
35	Manual Monthly Expense		803	803	803	803	803	803	803	803	803	803	803	803
36	<b>Total Monthly Expense</b>		<b>15,865</b>	<b>15,869</b>	<b>15,883</b>	<b>15,891</b>	<b>15,897</b>	<b>15,904</b>	<b>15,913</b>	<b>15,922</b>	<b>15,930</b>	<b>15,937</b>	<b>15,945</b>	<b>20,339</b>
<b>Hydro Production- FERCs 330-336</b>														
37	Bartlett Ferry		133,923	133,937	133,951	133,965	133,978	133,992	134,006	134,020	134,034	134,048	134,062	134,062
38	Barton		13,292	13,299	13,305	13,312	13,319	13,326	13,332	13,339	13,346	13,352	13,359	13,359
39	Central Ga Hqs		36,367	374	381	387	394	401	408	414	421	428	434	435
40	Flint River		34,684	35,605	36,566	37,507	38,448	39,388	40,329	41,269	42,211	43,177	44,118	45,263
41	Goat Rock		94,860	101,398	108,117	114,835	121,553	128,271	134,989	141,708	148,426	155,144	161,862	168,276
42	Lloyd Shoals		27,691	27,701	27,712	27,722	27,733	27,743	27,754	27,764	27,775	27,785	27,796	27,796
43	McIntosh 2		12,196	12,227	12,258	12,290	12,321	12,353	12,384	12,415	12,447	12,588	12,590	12,621
44	Nacoochee		8,185	8,192	8,199	8,206	8,212	8,219	8,226	8,232	8,239	8,246	8,253	8,253
45	North Highlands		22,476	24,902	27,328	29,755	32,181	34,607	37,034	39,460	41,886	44,313	46,739	51,910
46	Oliver Dam		28,674	31,087	33,500	35,913	38,326	40,738	43,151	45,564	47,977	50,390	52,803	55,221
47	Simsboro Dam		58,223	58,622	59,021	59,420	59,819	60,219	60,618	61,017	61,416	61,815	62,214	54,624
48	Tallulah Falls		30,372	30,379	30,387	30,394	30,401	30,408	30,415	30,422	30,429	30,437	30,444	30,444
49	Terrara		19,495	19,502	19,510	19,517	19,524	19,531	19,538	19,545	19,552	19,560	19,567	19,567
50	Walton		55,045	55,045	55,045	55,045	55,045	55,045	55,045	55,045	55,045	55,045	55,045	55,045
51	Walston Dam		231,070	234,477	237,884	241,291	244,697	248,104	251,511	254,917	258,324	261,731	265,138	268,541
52	Yamaha		10,170	10,424	10,677	10,931	11,184	11,438	11,692	11,945	12,199	12,452	12,706	12,954
53	Rocky Mountain 1-3		179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597	179,597
54	<b>Total Depreciable balance</b>		<b>506,141</b>	<b>518,197</b>	<b>526,253</b>	<b>534,309</b>	<b>542,365</b>	<b>550,421</b>	<b>558,477</b>	<b>566,533</b>	<b>574,589</b>	<b>582,645</b>	<b>590,701</b>	<b>598,757</b>
55	<b>Total Non Depreciable balance</b>		<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>	<b>40,008</b>
56	<b>Total Hydro Production</b>		<b>1,006,149</b>	<b>1,018,205</b>	<b>1,036,261</b>	<b>1,054,317</b>	<b>1,072,374</b>	<b>1,090,430</b>	<b>1,108,486</b>	<b>1,126,617</b>	<b>1,144,748</b>	<b>1,162,760</b>	<b>1,181,016</b>	<b>1,197,227</b>
<b>Total Hydro Depreciation Expense</b>														
57	<b>2019 Proposed Annual Rate</b>	2.529%												
58	Monthly Calculated Expense		1,837	2,023	2,062	2,100	2,138	2,176	2,214	2,252	2,290	2,328	2,367	2,147
59	Manual Monthly Expense		17	17	17	17	17	17	17	17	17	17	17	17
60	<b>Total Monthly Expense</b>		<b>1,854</b>	<b>2,040</b>	<b>2,078</b>	<b>2,116</b>	<b>2,154</b>	<b>2,192</b>	<b>2,231</b>	<b>2,269</b>	<b>2,307</b>	<b>2,345</b>	<b>2,383</b>	<b>2,421</b>
<b>Other Production- FERCs 340-346</b>														
61	Bowdoin CT		1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
62	Community Solar		3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143
63	McIntosh CC CT		12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553	12,553
64	Falkons Solar		3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379	3,379
65	Fort Benning Solar		65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636	65,636
66	Fort Gordon Solar		65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443	65,443
67	Fort Stewart Solar		66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652	66,652
68	Kings Bay Solar		66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956	66,956
69	Marine Corps - Albany Solar		436,318	436,318	436,318	436,318	436,318	436,318	502,911	502,911	502,911	502,911	502,911	520,411
70	McDonough CT		13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084	13,084
71	McIntosh CC CT		725,461	725,518	725,411	727,495	731,245	731,301	731,358	731,414	731,470	731,647	731,703	731,760
72	McDonough CTs		228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	228,756	230,024
73	Memphis CT		61,524	61,540	61,557	62,785	62,721	62,738	62,755	62,771	63,085	63,102	63,118	63,135
74	Ti 1801		1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1			

Georgia Power Company  
Depreciation Expense  
Per Staff  
Calendar Year 2022

Exhibit (RS/RT-2)  
Schedule F-1  
Page 17 of 17

Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Depr. Rate (A)	Jan-22 (AA)	Feb-22 (AB)	Mar-22 (AC)	Apr-22 (AD)	May-22 (AE)	Jun-22 (AF)	Jul-22 (AG)	Aug-22 (AH)	Sep-22 (AI)	Oct-22 (AJ)	Nov-22 (AK)	Dec-22 (AL)
<b>Transmission Plant- FERCs 350-359</b>														
91	Total Depreciable balance		6,725,937	6,786,320	6,791,236	6,800,671	6,814,022	6,841,571	6,904,689	6,937,991	6,973,201	7,012,814	7,052,329	7,095,861
92	Non Depreciable balance		431,293	431,696	431,749	431,803	431,858	431,912	432,072	432,232	432,391	432,552	432,713	433,026
93	Total Transmission Plant		7,157,230	7,218,016	7,222,986	7,232,475	7,245,880	7,273,482	7,336,760	7,370,223	7,405,593	7,445,366	7,485,042	7,528,886
<b>Transmission Depreciation Expense</b>														
94	2019 Proposed Annual Rate	2.196%												
95	Monthly Calculated Expense		12,288	12,297	12,407	12,416	12,433	12,458	12,508	12,624	12,685	12,749	12,822	12,894
96	Manual Monthly Expense		450	450	450	450	450	450	450	450	450	450	450	450
97	Total Monthly Expense		12,737	12,746	12,857	12,866	12,883	12,907	12,958	13,073	13,134	13,199	13,271	13,344
<b>Distribution Plant- FERCs 360-362 &amp; 364-373</b>														
98	Total Depreciable balance		11,908,035	11,948,303	12,097,492	12,127,154	12,158,477	12,307,223	12,358,382	12,413,531	12,582,252	12,636,812	12,689,619	12,865,237
99	Non Depreciable balance		162,283	162,283	162,283	162,683	162,683	162,683	162,683	162,683	162,683	162,683	162,683	162,683
100	Total Distribution Plant		12,070,319	12,110,587	12,259,775	12,289,837	12,321,160	12,469,906	12,521,065	12,576,214	12,744,935	12,799,495	12,852,302	13,027,920
<b>Distribution Depreciation Expense</b>														
101	2019 Proposed Annual Rate	2.7%												
102	Monthly Calculated Expense		26,748	26,793	26,883	27,219	27,286	27,356	27,691	27,806	27,930	28,310	28,433	28,551
103	Manual Monthly Expense		153	153	153	153	153	153	153	153	153	153	153	153
104	Total Monthly Expense		26,901	26,946	27,037	27,372	27,439	27,510	27,844	27,960	28,084	28,463	28,586	28,705
105	Total GPC Unregulated ODL Depreciable balance		732,228	738,951	746,275	754,648	763,041	772,016	780,958	790,418	799,366	809,340	818,785	828,256
<b>Distribution - Unregulated ODL</b>														
106	2019 Proposed Annual Rate	3.47%												
107	Monthly Calculated Expense		2,098	2,117	2,137	2,158	2,182	2,206	2,232	2,258	2,286	2,311	2,340	2,368
<b>Total Distribution Depreciation Expense</b>														
108	2019 Proposed Annual Rates													
109	Monthly Calculated Expense		28,846	28,910	29,020	29,377	29,468	29,563	29,923	30,064	30,216	30,621	30,773	30,919
110	Manual Monthly Expense		152	152	152	152	151	151	151	151	151	159	159	160
111	Total Monthly Expense		28,997	29,062	29,172	29,529	29,620	29,714	30,075	30,216	30,367	30,781	30,932	31,079
<b>General Plant- FERCs 289, 390, 392.1-4, 396, &amp; 397</b>														
<b>General Plant Balances</b>														
112	390 Structures		521,777	524,976	528,175	531,374	534,573	537,772	540,971	544,170	547,369	550,568	553,767	558,804
113	392 Transportation Equipment		456,316	459,497	462,679	465,860	469,042	472,223	475,405	478,586	481,768	484,949	488,131	491,327
114	396 Power Operated Equipment		44,224	44,700	45,175	45,651	46,126	46,601	47,077	47,552	48,028	48,503	48,978	49,456
115	397 Communications		501,492	503,895	506,297	508,700	511,102	513,505	517,929	522,354	526,779	531,203	535,628	542,338
116	Amortizable and Non Depreciable balance		517,546	519,289	521,032	522,813	524,598	526,379	528,140	529,884	531,627	533,370	535,114	536,865
117	Total General Plant		2,041,355	2,052,356	2,063,358	2,074,397	2,085,441	2,096,480	2,109,522	2,122,546	2,135,570	2,148,594	2,161,618	2,178,790
118	390 Structures													
119	Proposed Monthly Depreciation Rates	1.759%	760	765	770	774	779	784	788	793	798	802	807	812
120	392 Transportation Equipment*													
121	Proposed Monthly Depreciation Rates	4.316%	1,630	1,641	1,653	1,664	1,676	1,687	1,698	1,710	1,721	1,733	1,744	1,756
122	396 Power Operated Equipment*													
123	Proposed Monthly Depreciation Rates	11.260%	411	415	420	424	429	433	438	442	447	451	455	460
124	397 Communications													
125	Proposed Monthly Depreciation Rates	2.715%	1,129	1,135	1,140	1,145	1,151	1,156	1,162	1,172	1,182	1,192	1,202	1,212
126	Amortizable and Non Depreciable													
127	Proposed Monthly Manual Expense		1,027	1,037	1,046	1,056	1,066	1,076	1,086	1,096	1,105	1,115	1,125	1,134
128	Reclassified Transportation and Power Operated Equipment*													
129	Proposed Monthly Depreciation Rates		(2,041)	(2,057)	(2,072)	(2,088)	(2,104)	(2,120)	(2,136)	(2,152)	(2,168)	(2,184)	(2,200)	(2,216)
<b>Total General Depreciation Expense</b>														
130	2019 Proposed Annual Rates													
131	Monthly Calculated Expense		1,889	1,899	1,910	1,920	1,930	1,940	1,950	1,965	1,979	1,994	2,009	2,024
132	Manual Monthly Expense		1,027	1,037	1,046	1,056	1,066	1,076	1,086	1,096	1,105	1,115	1,125	1,134
133	Total Monthly Expense		2,916	2,936	2,956	2,976	2,996	3,016	3,036	3,060	3,085	3,109	3,134	3,158
<b>Total Company Depreciation Expense</b>														
134	2019 Proposed Annual Rates													
135	Monthly Calculated Expense		89,504	89,780	90,098	90,609	90,817	91,039	91,513	92,014	92,293	92,892	93,186	97,869
136	Manual Monthly Expense		7,348	7,358	7,367	7,377	7,387	7,397	7,407	7,416	7,426	7,434	7,444	7,463
137	Total Monthly Expense		97,252	97,537	97,866	98,386	98,604	98,836	99,320	99,831	100,119	100,736	101,040	105,733
138	Total Annual Depreciation Expense												Calendar Year 2022	1,195,259

Notes and Source:  
Per the attachment provided in the Company's response to STF-L&A-2-3 and STF-L&A-2-4  
Col A: Per the recommended depreciation rates by Staff witness William Dunkled

Georgia Power Company  
Accumulated Deferred Income Taxes - Impact of Depreciation Rates

Retail Electric Amounts  
(Thousands of Dollars)

Line No.	Description	Forecasted Test Year Ending 7/31/2020 (A)	Calendar 2020 (B)	Calendar 2021 (C)	Calendar 2022 (D)
1	Total Company Adjustment to Accumulated Depreciation	\$ 51,847	\$ 52,612	\$ 158,517	\$ 265,713
2	Combined Federal and State Tax Rate	25.296%	25.296%	25.296%	25.296%
3	Total Company Adjustment to ADIT	\$ (13,115)	\$ (13,308)	\$ (40,098)	\$ (67,214)
4	ADIT Jurisdictional Factor	97.81096%	97.87255%	97.90312%	97.89042%
5	Jurisdictional Adjustment to ADIT	\$ (12,828)	\$ (13,025)	\$ (39,257)	\$ (65,796)

Notes and Source:

Line 1: Per Schedule F-1, page 1

Line 2: Schedule A-1

Line 4: Per Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company):

Forecasted Test Year Ending 7/31/2020	Calendar 2020	Calendar 2021	Calendar 2022
Steam Plant-in-Service - Retail	\$ (5,061,956)	\$ (5,214,008)	\$ (5,298,725)
Steam Plant-in-Service - Adjusted Electric	\$ (5,175,244)	\$ (5,325,681)	\$ (5,412,915)
Depreciation Expense Jurisdictional Factor	97.81096%	97.90312%	97.89042%

EXHIBIT\_\_(RS/RT-3)

Georgia Power Company  
Docket No. 42516  
Exhibit \_\_ (RS/RT-3)  
Environmental Compliance Cost Recovery (ECCR) Tariff Adjustment Schedules  
Accompanying the Direct Testimony of Ralph C. Smith and Robert Trokey

Description	Primary Staff Witnesses	Confidential	No. of Pages	Page No.
<b>Revenue Requirement Summary Schedules</b>				
Computation of Test Year ECCR Revenue Requirement	R. Smith/R. Trokey	No	1	2
Computation of Plan Years 2020-2022 ECCR Revenue Requirement	R. Smith/R. Trokey	No	1	3
ECCR Investment and Expenses Per Company As-Filed	R. Smith/R. Trokey	No	1	4
Environmental State and Federal Income Taxes As-Filed	R. Smith/R. Trokey	No	1	5
ECCR Investment and Expenses Per Staff	R. Smith/R. Trokey	No	4	6-9
Environmental State and Federal Income Taxes Per Staff	R. Smith/R. Trokey	No	1	10
Company Errata Adjustments	R. Smith/R. Trokey	No	1	11
Staff Adjustment to Remove Contingencies	R. Smith/R. Trokey	No	1	12
Total Pages, Including Content Listing			12	

Georgia Power Company  
Environmental Compliance Cost Recovery (ECCR) Tariff  
Computation of Test Year ECCR Revenue Requirement

Exhibit \_\_ (RS/RT-3)  
Page 2 of 12

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Per Company Revenue Deficiency (A)	Per Staff Adjusted Revenue Deficiency (B)	Difference (C) = (B) - (A)
1	Retail Rate Base	\$ 3,346,626	\$ 3,321,490	\$ (25,136)
2	Requested Rate of Return	7.93%	6.69%	
3	Earnings Requirement	\$ 265,470	\$ 222,085	\$ (43,385)
4	Less: Earnings Available for Return	135,942	138,001	2,059
5	Earnings Deficiency	\$ 129,528	\$ 84,084	\$ (45,444)
6	Income Expansion Factor	74.602%	74.616%	
7	Total Revenue Deficiency	\$ 173,625	\$ 112,688	\$ (60,936)
8	2020-2022 Levelization Adjustment	(8,699)	-	8,699
9	Levelized Revenue Deficiency Applicable to ECCR Tariffs	\$ 164,926	\$ 112,688	\$ (52,237)

Notes and Source:

Col A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 3), Page 1 of 5

Col. B, line 2: Staff recommended rate of return calculated on Exhibit \_\_ (RS/RT-2), Schedule D, page 1

Col. B, line 6: Staff recommended income expansion factor calculated on Exhibit \_\_ (RS/RT-2), Schedule A-1, page 1



Georgia Power Company  
Environmental Compliance Cost Recovery (ECCR) Tariff  
Computation of Plan Years 2020-2022 ECCR Revenue Requirement

Exhibit \_\_ (RS/RT-3)  
Page 3 of 12

Calendar Years 2020-2022  
(Thousands of Dollars)

Line No.	Description	2020 (A)	2021 (B)	2022 (C)
<b><u>I. Per Company</u></b>				
1	Retail Rate Base	\$ 3,351,618	\$ 3,127,111	\$ 2,905,428 (a)
2	Requested Rate of Return	7.98%	8.07%	8.13% (b)
3	Earnings Requirement	\$ 267,506	\$ 252,464	\$ 236,216
4	Less: Earnings Available for Return	130,562	127,533	131,313 (a)
5	Earnings Deficiency	\$ 136,944	\$ 124,931	\$ 104,902
6	Income Expansion Factor	74.596%	74.597%	74.598% (c)
7	Total Revenue Deficiency	\$ 183,581	\$ 167,475	\$ 140,623
<b><u>II. Per Staff</u></b>				
8	Retail Rate Base	\$ 3,316,335	\$ 3,090,485	\$ 2,869,945 (d)
9	Requested Rate of Return	6.73%	6.75%	6.75% (e)
10	Earnings Requirement	\$ 223,040	\$ 208,759	\$ 193,581
11	Less: Earnings Available for Return	132,689	128,939	131,885 (d)
12	Earnings Deficiency	\$ 90,352	\$ 79,820	\$ 61,696
13	Income Expansion Factor	74.615%	74.616%	74.617% (f)
14	Total Revenue Deficiency	\$ 121,090	\$ 106,974	\$ 82,683
<b><u>III. Difference between Staff and Company</u></b>				
15	Total Revenue Deficiency	\$ (62,491)	\$ (60,501)	\$ (57,940)

Notes and Source

Note: Details may not add to totals due to rounding.

- (a) From Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 3 ECCR) Page 4
- (b) From Exhibit \_\_ (DPP/SPA/MBR-3, Schedule 2, Worksheets 2-4) for 2020, 2021, and 2022, respectively
- (c) From Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 2
- (d) Pages 7-9 of this Exhibit
- (e) Exhibit RS/RT-2, Schedule D, pages 2-4
- (f) Exhibit RS/RT-2, Schedule A-1, page 2

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Test	Calendar Years Ending		
		Period (b)	2020	2021	2022
		(A)	(B)	(C)	(D)
<b><u>Per Company</u></b>					
1	Retail Electric Plant in Service	\$ 4,561,717	\$ 4,636,136	\$ 4,662,306	\$ 4,688,871
2	Accumulated Depreciation	(963,604)	(1,020,143)	(1,224,236)	(1,429,075)
3	Net Plant in Service	<u>\$ 3,598,113</u>	<u>\$ 3,615,993</u>	<u>\$ 3,438,070</u>	<u>\$ 3,259,795</u>
4	Environmental Regulatory Assets	646,024	622,732	533,025	444,175
5	Accumulated Deferred Income Taxes	(897,512)	(887,108)	(843,985)	(798,542)
6	Total Rate Base	<u><u>\$ 3,346,626</u></u>	<u><u>\$ 3,351,618</u></u>	<u><u>\$ 3,127,111</u></u>	<u><u>\$ 2,905,428</u></u>
7	ECCR Tariff Revenues	\$ 527,018	\$ 526,813	\$ 526,854	\$ 525,569
8	Operating Expenses	(69,615)	(73,078)	(78,068)	(69,599)
9	Environmental Remediation Accrual	(14,392)	(14,392)	(14,392)	(14,392)
10	Depreciation Expense	(203,609)	(203,222)	(204,290)	(205,445)
11	Environmental Regulatory Assets Amortization	(90,563)	(90,563)	(88,850)	(88,853)
12	Earnings Before Taxes	<u>\$ 148,838</u>	<u>\$ 145,558</u>	<u>\$ 141,254</u>	<u>\$ 147,280</u>
13	Federal Income Taxes	(16,850)	(15,214)	(14,566)	(16,166)
14	State Income Taxes	3,954	219	846	200
15	Earnings Available for Return	<u>\$ 135,942</u>	<u>\$ 130,562</u>	<u>\$ 127,533</u>	<u>\$ 131,313</u>

## Notes and Source

Details may not add to totals due to rounding.

Cols. A-D: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 3 ECCR)

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
<b>Per Company</b>					
<b>State Tax Calculation</b>					
1	ECCR Revenues	\$ 527,018	\$ 526,813	\$ 526,854	\$ 525,569
2	Operating Expenses	(69,615)	(73,078)	(78,068)	(69,599)
3	Environmental Remediation Accrual	(14,392)	(14,392)	(14,392)	(14,392)
4	Depreciation Expense	(203,609)	(203,222)	(204,290)	(205,445)
5	Environmental Amortization	(90,563)	(90,563)	(88,850)	(88,853)
6	Interest Expense	(60,896)	(62,876)	(61,501)	(58,782)
7	Non-Deductible Depreciation Expense	14,957	16,165	16,155	16,208
8	State Income Tax Deduction	(5,595)	(5,375)	(5,215)	(5,693)
9	Earnings Subject to State Tax	\$ 97,304	\$ 93,472	\$ 90,692	\$ 99,013
10	State Tax Rate	5.75%	5.75%	5.75%	5.75%
11	State Tax on Environmental Expenses	\$ 5,595	\$ 5,375	\$ 5,215	\$ 5,693
12	State Tax Credits on Environmental Expenditures	(9,461)	(5,505)	(5,991)	(5,840)
13	State Protected Excess ADIT Amortization	(88)	(88)	(69)	(53)
14	Net State Income Tax - Environmental	\$ (3,954)	\$ (219)	\$ (846)	\$ (200)
<b>Federal Tax Calculation</b>					
15	ECCR Revenues	\$ 527,018	\$ 526,813	\$ 526,854	\$ 525,569
16	Operating Expenses	(69,615)	(73,078)	(78,068)	(69,599)
17	Environmental Remediation Accrual	(14,392)	(14,392)	(14,392)	(14,392)
18	Depreciation Expense	(203,609)	(203,222)	(204,290)	(205,445)
19	Environmental Amortization	(90,563)	(90,563)	(88,850)	(88,853)
20	Interest Expense	(60,896)	(62,876)	(61,501)	(58,782)
21	Non-Deductible Depreciation Expense	14,957	16,165	16,155	16,208
22	State Income Tax Deduction	3,954	219	846	200
23	Earnings Subject to Federal Tax	\$ 106,853	\$ 99,066	\$ 96,752	\$ 104,906
24	Federal Tax Rate	21.00%	21.00%	21.00%	21.00%
25	Federal Tax on Environmental Expenses	\$ 22,439	\$ 20,804	\$ 20,318	\$ 22,030
26	Federal Protected Excess ADIT Amortization	(5,589)	(5,589)	(5,752)	(5,864)
27	Net Federal Income Tax - Environmental	\$ 16,850	\$ 15,214	\$ 14,566	\$ 16,166

Notes and Source

Details may not add to totals due to rounding.

For the 12 Months Ending July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Interest Synchronization (D)	Adjustment to Remove Contingency* (E)	Staff Adjusted (F)
<b>Per Staff</b>							
1	Retail Electric Plant in Service	\$ 4,561,717	\$ (13,386)	\$ 4,548,331		\$ (16,601)	\$ 4,531,730
2	Accumulated Depreciation	(963,604)	2,010	\$ (961,594)		\$ 340	\$ (961,254)
3	Net Plant in Service	\$ 3,598,113	\$ (11,376)	\$ 3,586,737	\$ -	\$ (16,261)	\$ 3,570,476
4	Environmental Regulatory Assets	646,024	-	\$ 646,024			\$ 646,024
5	Accumulated Deferred Income Taxes	(897,512)	2,324	\$ (895,187)		\$ 177	\$ (895,010)
6	Total Rate Base	\$ 3,346,626	\$ (9,052)	\$ 3,337,574	\$ -	\$ (16,084)	\$ 3,321,490
7	ECCR Tariff Revenues	\$ 527,018	\$ (229)	\$ 526,789			\$ 526,789
8	Operating Expenses	(69,615)	125	\$ (69,490)			\$ (69,490)
9	Environmental Remediation Accrual	(14,392)	-	\$ (14,392)			\$ (14,392)
10	Depreciation Expense	(203,609)	332	\$ (203,278)		\$ 728	\$ (202,550)
11	Environmental Regulatory Assets Amortization	(90,563)	-	\$ (90,563)			\$ (90,563)
12	Earnings Before Taxes	\$ 148,838	\$ 228	\$ 149,066	\$ -	\$ 728	\$ 149,794
13	Federal Income Taxes	(16,850)	(68)	\$ (16,917)	\$ 946		\$ (15,971)
14	State Income Taxes	3,954	(50)	\$ 3,904	\$ 275		\$ 4,179
15	Earnings Available for Return	\$ 135,942	\$ 110	\$ 136,052	\$ 1,221	\$ 728	\$ 138,001

## Notes and Source

Col. A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4

Cols. B-C: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 3 ECCR Errata)

Col. D: See page 10

Col. E: See page 12

\* The income tax impact of the contingency related adjustment to depreciation expense is reflected on page 10

Georgia Power Company  
Environmental Compliance Cost Recovery (ECCR) Tariff  
ECCR Investment and Expenses Per Staff

Exhibit (RS/RT-3)  
Page 7 of 12

Calendar 2020  
(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Interest Synchronization (D)	Staff Adjustment to Remove Contingency* (E)	Staff Adjusted (F)
<b>Per Staff</b>							
1	Retail Electric Plant in Service	\$ 4,636,136	\$ (22,953)	\$ 4,613,183		\$ (20,684)	\$ 4,592,499
2	Accumulated Depreciation	\$ (1,020,143)	\$ 3,555	\$ (1,016,588)		\$ 621	\$ (1,015,967)
3	Net Plant in Service	\$ 3,615,993	\$ (19,398)	\$ 3,596,596		\$ (20,063)	\$ 3,576,533
4	Environmental Regulatory Assets	\$ 622,732	\$ -	\$ 622,732	\$ -		\$ 622,732
5	Accumulated Deferred Income Taxes	\$ (887,108)	\$ 3,914	\$ (883,194)		\$ 264	\$ (882,930)
6	Total Rate Base	\$ 3,351,618	\$ (15,484)	\$ 3,336,134	\$ -	\$ (19,799)	\$ 3,316,335
7	ECCR Tariff Revenues	\$ 526,813	\$ (393)	\$ 526,420			\$ 526,420
8	Operating Expenses	\$ (73,078)	\$ 213	\$ (72,865)			\$ (72,865)
9	Environmental Remediation Accrual	\$ (14,392)	\$ -	\$ (14,392)			\$ (14,392)
10	Depreciation Expense	\$ (203,222)	\$ 569	\$ (202,653)		\$ 921	\$ (201,732)
11	Environmental Regulatory Assets Amortization	\$ (90,563)	\$ -	\$ (90,563)			\$ (90,563)
12	Earnings Before Taxes	\$ 145,558	\$ 389	\$ 145,947	\$ -	\$ 921	\$ 146,868
13	Federal Income Taxes	\$ (15,214)	\$ (123)	\$ (15,337)	\$ 778		\$ (14,559)
14	State Income Taxes	\$ 219	\$ (65)	\$ 154	\$ 226		\$ 380
15	Earnings Available for Return	\$ 130,562	\$ 201	\$ 130,763	\$ 1,004	\$ 921	\$ 132,689

Notes and Source

Col. A: Company Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4  
Cols. B-C: Company Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR Errata)  
Col. D: See page 10  
Col. E: See page 12

\* The income tax impact of the contingency related adjustment to depreciation expense is reflected on page 10

## Calendar 2021

(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Interest Synchronization (D)	Staff Adjustment to Remove Contingency* (E)	Staff Adjusted (F)
<b>Per Staff</b>							
1	Retail Electric Plant in Service	\$ 4,662,306	\$ (25,139)	\$ 4,637,167		\$ (22,169)	\$ 4,614,998
2	Accumulated Depreciation	\$ (1,224,236)	\$ 4,398	\$ (1,219,837)		\$ 1,577	\$ (1,218,260)
3	Net Plant in Service	\$ 3,438,070	\$ (20,741)	\$ 3,417,330	\$ -	\$ (20,592)	\$ 3,396,738
4	Environmental Regulatory Assets	\$ 533,025	\$ -	\$ 533,025			\$ 533,025
5	Accumulated Deferred Income Taxes	\$ (843,985)	\$ 4,278	\$ (839,707)		\$ 429	\$ (839,278)
6	Total Rate Base	\$ 3,127,111	\$ (16,463)	\$ 3,110,648	\$ -	\$ (20,163)	\$ 3,090,485
7	ECCR Tariff Revenues	\$ 526,854	\$ (710)	\$ 526,144			\$ 526,144
8	Operating Expenses	\$ (78,068)	\$ 289	\$ (77,779)			\$ (77,779)
9	Environmental Remediation Accrual	\$ (14,392)	\$ -	\$ (14,392)			\$ (14,392)
10	Depreciation Expense	\$ (204,290)	\$ 574	\$ (203,716)		\$ 989	\$ (202,727)
11	Environmental Regulatory Assets Amortization	\$ (88,850)	\$ -	\$ (88,850)			\$ (88,850)
12	Earnings Before Taxes	\$ 141,254	\$ 153	\$ 141,407	\$ -	\$ 989	\$ 142,396
13	Federal Income Taxes	\$ (14,566)	\$ (81)	\$ (14,648)	\$ 314		\$ (14,333)
14	State Income Taxes	\$ 846	\$ (60)	\$ 785	\$ 91		\$ 876
15	Earnings Available for Return	\$ 127,533	\$ 12	\$ 127,545	\$ 405	\$ 989	\$ 128,939

## Notes and Source

Col. A: Company Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4

Cols. B-C: Company Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR Errata)

Col. D: See page 10

Col. E: See page 12

\* The income tax impact of the contingency related adjustment to depreciation expense is reflected on page 10

## Calendar 2022

(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Interest Synchronization (D)	Staff Adjustment to Remove Contingency* (E)	Staff Adjusted (F)
<b>Per Staff</b>							
1	Retail Electric Plant in Service	\$ 4,688,871	\$ (25,326)	\$ 4,663,545		\$ (22,555)	\$ 4,640,990
2	Accumulated Depreciation	\$ (1,429,075)	\$ 4,975	\$ (1,424,101)		\$ 2,574	\$ (1,421,527)
3	Net Plant in Service	\$ 3,259,795	\$ (20,351)	\$ 3,239,445		\$ (19,981)	\$ 3,219,464
4	Environmental Regulatory Assets	\$ 444,175	\$ -	\$ 444,175	\$ -		\$ 444,175
5	Accumulated Deferred Income Taxes	\$ (798,542)	\$ 4,284	\$ (794,259)		\$ 565	\$ (793,694)
6	Total Rate Base	\$ 2,905,428	\$ (16,067)	\$ 2,889,361	\$ -	\$ (19,416)	\$ 2,869,945
7	ECCR Tariff Revenues	\$ 525,569	\$ (1,022)	\$ 524,547			\$ 524,547
8	Operating Expenses	\$ (69,599)	\$ 187	\$ (69,411)			\$ (69,411)
9	Environmental Remediation Accrual	\$ (14,392)	\$ -	\$ (14,392)			\$ (14,392)
10	Depreciation Expense	\$ (205,445)	\$ 578	\$ (204,867)		\$ 1,004	\$ (203,863)
11	Environmental Regulatory Assets Amortization	\$ (88,853)	\$ -	\$ (88,853)			\$ (88,853)
12	Earnings Before Taxes	\$ 147,280	\$ (257)	\$ 147,023	\$ -	\$ 1,004	\$ 148,027
13	Federal Income Taxes	\$ (16,166)	\$ 0	\$ (16,166)	\$ (106)		\$ (16,273)
14	State Income Taxes	\$ 200	\$ (39)	\$ 161	\$ (31)		\$ 130
15	Earnings Available for Return	\$ 131,313	\$ (295)	\$ 131,018	\$ (137)	\$ 1,004	\$ 131,885

## Notes and Source

Col. A: Company Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4

Cols. B-C: Company Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR Errata)

Col. D: See page 10

Col. E: See page 12

\* The income tax impact of the contingency related adjustment to depreciation expense is reflected on page 10

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Test Period			
		(A)	(B)	(C)	(D)
<b>Per Staff</b>					
<b>State Tax Calculation</b>					
1	ECCR Revenues	\$ 526,789	\$ 526,420	\$ 526,144	\$ 524,547
2	Operating Expenses	(69,490)	(72,865)	(77,779)	(69,411)
3	Environmental Remediation Accrual	(14,392)	(14,392)	(14,392)	(14,392)
4	Depreciation Expense - see Note A below	(202,550)	(201,732)	(202,727)	(203,863)
5	Environmental Amortization	(90,563)	(90,563)	(88,850)	(88,853)
6	Interest Expense - see line 34 below	(66,240)	(67,438)	(63,754)	(58,923)
7	Non-Deductible Depreciation Expense	14,938	16,136	16,125	16,178
8	State Income Tax Deduction	(5,615)	(5,410)	(5,239)	(5,695)
9	Earnings Subject to State Tax	\$ 92,876	\$ 90,156	\$ 89,528	\$ 99,587
10	State Tax Rate	5.75%	5.75%	5.75%	5.75%
11	State Tax on Environmental Expenses	\$ 5,340	\$ 5,184	\$ 5,148	\$ 5,726
12	State Tax Credits on Environmental Expenditures	(9,431)	(5,476)	(5,955)	(5,803)
13	State Protected Excess ADIT Amortization	(88)	(88)	(69)	(53)
14	Net State Income Tax - Environmental	\$ (4,179)	\$ (380)	\$ (876)	\$ (130)
15	Net State Income Tax - Environmental - per Company Errata	\$ (3,904)	\$ (154)	\$ (785)	\$ (161)
16	Staff Adjustment to State Income Tax - Environmental	\$ 275	\$ 226	\$ 91	\$ (31)
<b>Federal Tax Calculation</b>					
17	ECCR Revenues	\$ 526,789	\$ 526,420	\$ 526,144	\$ 524,547
18	Operating Expenses	(69,490)	(72,865)	(77,779)	(69,411)
19	Environmental Remediation Accrual	(14,392)	(14,392)	(14,392)	(14,392)
20	Depreciation Expense - see Note A below	(202,550)	(201,732)	(202,727)	(203,863)
21	Environmental Amortization	(90,563)	(90,563)	(88,850)	(88,853)
22	Interest Expense - see line 34 below	(66,240)	(67,438)	(63,754)	(58,923)
23	Non-Deductible Depreciation Expense	14,938	16,136	16,125	16,178
24	State Income Tax Deduction	4,179	380	876	130
25	Earnings Subject to Federal Tax	\$ 102,670	\$ 95,945	\$ 95,643	\$ 105,412
26	Federal Tax Rate	21.00%	21.00%	21.00%	21.00%
27	Federal Tax on Environmental Expenses	\$ 21,561	\$ 20,149	\$ 20,085	\$ 22,137
28	Federal Protected Excess ADIT Amortization	(5,589)	(5,589)	(5,752)	(5,864)
29	Net Federal Income Tax - Environmental	\$ 15,971	\$ 14,559	\$ 14,333	\$ 16,273
30	Net Federal Income Tax - Environmental - per Company Errata	\$ 16,917	\$ 15,337	\$ 14,648	\$ 16,166
31	Staff Adjustment to Federal Income Tax - Environmental	\$ 946	\$ 778	\$ 314	\$ (106)

**Notes and Source**

Details may not add to totals due to rounding.

Cols. A-D: Amounts from Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR Errata) except where noted below:

A: Staff adjusted depreciation expense calculated on page 12

	Test Period			
		2020	2021	2022
<b>Interest Synchronization Adjustment Calculation</b>				
32	Rate Base - see pages 6-9	\$ 3,321,490	\$ 3,090,485	\$ 2,869,945
33	Weighted Cost of Debt - see Exhibit (RS/RT-2), Schedule D, pages 1-4	1.99%	2.06%	2.05%
34	Interest Expense - to lines 6 and 22 above	\$ 66,240	\$ 63,754	\$ 58,923



For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Test Period			
		(A)	(B)	(C)	(D)
1	Retail Electric Plant in Service	\$ (13,386)	\$ (22,953)	\$ (25,139)	\$ (25,326)
2	Accumulated Depreciation	2,010	3,555	4,398	4,975
3	Net Plant in Service	\$ (11,376)	\$ (19,398)	\$ (20,741)	\$ (20,351)
4	Environmental Regulatory Assets	-	-	-	-
5	Accumulated Deferred Income Taxes	2,324	3,914	4,278	4,284
6	Total Rate Base	\$ (9,052)	\$ (15,484)	\$ (16,463)	\$ (16,067)
7	ECCR Tariff Revenues	(229)	(393)	(710)	(1,022)
8	Operating Expenses	125	213	289	187
9	Environmental Remediation Accrual	-	-	-	-
10	Depreciation Expense	332	569	574	578
11	Environmental Regulatory Assets Amortization	-	-	-	-
12	Earnings Before Taxes	\$ 228	\$ 389	\$ 153	\$ (257)
13	Federal Income Taxes	(68)	(123)	(81)	0
14	State Income Taxes	(50)	(65)	(60)	(39)
15	Earnings Available for Return	\$ 110	\$ 201	\$ 12	\$ (295)

Notes and Source

Details may not add to totals due to rounding.

Cols. A-D: Amounts from Errata Exhibit 1, page 9 from the Company' Errata filing

Georgia Power Company  
Environmental Compliance Cost Recovery (ECCR) Tariff  
Staff Adjustment to Remove Contingencies

Exhibit (RS/RT-3)  
Page 12 of 12

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Forecasted Test Year Ending 7/31/2020 (A)	2020 (B)	2021 (C)	2022 (D)
<b>Rate Base</b>					
1	Staff Adjustment to Remove Contingency Costs From Plant in Service	\$ (16,601)	\$ (20,684)	\$ (22,169)	\$ (22,555)
2	Staff Adjustment to Remove Contingency Costs From Accumulated Depreciation	\$ 340	\$ 621	\$ 1,577	\$ 2,574
3	Net Adjustment to Plant in Service	<u>\$ (16,261)</u>	<u>\$ (20,063)</u>	<u>\$ (20,592)</u>	<u>\$ (19,981)</u>
4	Staff Adjustment to Accumulated Deferred Income Taxes	\$ 177	\$ 264	\$ 429	\$ 565
5	Net Adjustment to Rate Base	<u>\$ (16,084)</u>	<u>\$ (19,799)</u>	<u>\$ (20,163)</u>	<u>\$ (19,416)</u>
<b>Operating Income</b>					
5	Staff Adjustment to Reflect Removing Contingency on Depreciation Expense	<u>\$ (728)</u>	<u>\$ (921)</u>	<u>\$ (989)</u>	<u>\$ (1,004)</u>

Notes and Source

Cols. A-D: Amounts from Company Attachment ECCR Contingency, which was provided in an email from Georgia Power dated October 11, 2019

**Staff Adjusted Depreciation Expense calculated below:**

6	Per Company Depreciation Expense Per Errata Filing	203,278	\$ 202,653	\$ 203,716	\$ 204,867
7	Staff Adjustment to Depreciation Expense	<u>\$ (728)</u>	<u>\$ (921)</u>	<u>\$ (989)</u>	<u>\$ (1,004)</u>
8	Staff Adjusted Depreciation Expense*	<u>\$ 202,550</u>	<u>\$ 201,732</u>	<u>\$ 202,727</u>	<u>\$ 203,863</u>

\* The Staff adjusted depreciation expense amounts flow to page 10, lines 4 and 20

EXHIBIT\_\_(RS/RT-4)

Georgia Power Company  
Docket No. 42516  
Exhibit\_\_(RS/RT-4)  
Demand Side Management (DSM) Tariff Adjustment Schedules  
Accompanying the Direct Testimony of Ralph C. Smith and Robert Trokey

<b>Description</b>	<b>Primary Staff Witnesses</b>	<b>Confidential</b>	<b>No. of Pages</b>	<b>Page No.</b>
<b>Revenue Requirement Summary Schedules</b>				
DSM Revenue Requirement Summary	R. Smith/R. Trokey	No	2	2-3
Staff Adjustments	R. Smith/R. Trokey	No	4	4-7
Carrying Cost Summary	R. Smith/R. Trokey	No	1	8
Carrying Cost Calculation Details - Company	R. Smith/R. Trokey	No	2	9-10
Carrying Cost Calculation Details - Staff	R. Smith/R. Trokey	No	2	11-12
Capital Structure and Cost Rates	R. Smith/R. Trokey	No	5	13-17
Total Pages, Including Content Listing			17	

Georgia Power Company  
Demand Side Management (DSM) Tariffs Revenue Requirement  
Retail Electric Amounts  
(Thousand of Dollars)

Exhibit \_\_ (RS/RT-4)  
Page 2 of 17

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
1	DSM Tariff Increase - Per Company	\$ 14,330	\$ 14,377	\$ 16,414	\$ 17,401
2	DSM Tariff Increase - Per Staff	<u>\$ 11,869</u>	<u>\$ 11,915</u>	<u>\$ 13,171</u>	<u>\$ 13,988</u>
3	DSM Tariff Adjustment	<u>\$ (2,461)</u>	<u>\$ (2,462)</u>	<u>\$ (3,243)</u>	<u>\$ (3,413)</u>

Notes and Source:

Line 1: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 4)

Line 2: see pages 4-7

Georgia Power Company  
Demand Side Management (DSM) Tariffs - Company As-Filed Calculation  
Retail Electric Amounts  
(Thousand of Dollars)

Exhibit \_\_ (RS/RT-4)  
Page 3 of 17

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
	<b>Residential Programs</b>				
1	Incentive Costs	\$ 9,508	\$ 9,508	\$ 9,717	\$ 9,931
2	Non-Incentive Costs	\$ 9,227	\$ 9,227	\$ 9,912	\$ 10,054
3	Cross-Cutting Costs	\$ 1,725	\$ 1,725	\$ 1,619	\$ 1,558
4	Additional Sum	\$ 3,319	\$ 3,319	\$ 3,319	\$ 3,319
5	Previously-Certified Program Costs & Other DSM	\$ 12,244	\$ 12,244	\$ 12,436	\$ 12,640
6	<b>Residential Sub-total</b>	\$ 36,023	\$ 36,023	\$ 37,003	\$ 37,503
	<b>Commercial Programs</b>				
7	Incentive Costs	\$ 13,568	\$ 13,568	\$ 13,858	\$ 14,128
8	Non-Incentive Costs	\$ 17,293	\$ 17,293	\$ 18,364	\$ 18,618
9	Cross-Cutting Costs	\$ 1,725	\$ 1,725	\$ 1,619	\$ 1,558
10	Additional Sum	\$ 11,691	\$ 11,691	\$ 11,686	\$ 11,666
11	Previously-Certified Program Costs & Other DSM	\$ 3,136	\$ 3,136	\$ 3,205	\$ 3,275
12	<b>Commercial Sub-total</b>	\$ 47,411	\$ 47,411	\$ 48,732	\$ 49,245
13	<b>Total Residential and Commercial DSM Costs</b>	\$ 83,434	\$ 83,434	\$ 85,735	\$ 86,748
14	<b>Projected DSM Under-Recovery 12/31/19</b>	\$ 4,287	\$ 4,287	\$ 4,287	\$ 4,287
15	<b>Carrying Cost on DSM Under-Recovery</b>	\$ 679	\$ 679	\$ 355	\$ 28
16	<b>Total DSM Tariff Costs</b>	\$ 88,400	\$ 88,400	\$ 90,377	\$ 91,063
17	DSM Revenues Included in Current Tariffs	\$ 74,090	\$ 74,044	\$ 73,987	\$ 73,686
18	<b>DSM Tariff Increases Before Tax</b>	\$ 14,310	\$ 14,356	\$ 16,390	\$ 17,376
19	Federal and State Income Taxes	\$ 3,620	\$ 3,632	\$ 4,146	\$ 4,396
20	DSM Tariff Increases After Tax	\$ 10,690	\$ 10,725	\$ 12,244	\$ 12,981
21	Income Expansion Factor	74.602%	74.596%	74.597%	74.598%
22	<b>DSM Tariff Increase</b>	\$ 14,330	\$ 14,377	\$ 16,414	\$ 17,401
23	<b>DSM Tariff Incremental Increase/(Decrease)</b>	\$ 14,377	\$ 14,377	\$ 2,037	\$ 987

Notes and Source:  
Cols. A-D: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 4)

Georgia Power Company  
Demand Side Management (DSM) Tariffs - Staff Calculation  
Retail Electric Amounts

Exhibit (RS/RT-4)  
Page 4 of 17

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Adjustment to Carrying Costs (D)	Staff Adjusted (E)
<b>Residential Programs</b>						
1	Incentive Costs	\$ 9,508	\$ 422	\$ 9,930		\$ 9,930
2	Non-Incentive Costs	\$ 9,227	\$ 652	\$ 9,880		\$ 9,880
3	Cross-Cutting Costs	\$ 1,725	\$ -	\$ 1,725		\$ 1,725
4	Additional Sum	\$ 3,319	\$ (2,668)	\$ 651		\$ 651
5	Previously-Certified Program Costs & Other DSM	\$ 12,244	\$ 287	\$ 12,531		\$ 12,531
6	<b>Residential Sub-total</b>	<u>\$ 36,023</u>	<u>\$ (1,306)</u>	<u>\$ 34,717</u>	<u>\$ -</u>	<u>\$ 34,717</u>
<b>Commercial Programs</b>						
7	Incentive Costs	\$ 13,568	\$ 321	\$ 13,889		\$ 13,889
8	Non-Incentive Costs	\$ 17,293	\$ 314	\$ 17,607		\$ 17,607
9	Cross-Cutting Costs	\$ 1,725	\$ -	\$ 1,725		\$ 1,725
10	Additional Sum	\$ 11,691	\$ (1,199)	\$ 10,492		\$ 10,492
11	Previously-Certified Program Costs & Other DSM	\$ 3,136	\$ (536)	\$ 2,600		\$ 2,600
12	<b>Commercial Sub-total</b>	<u>\$ 47,411</u>	<u>\$ (1,100)</u>	<u>\$ 46,311</u>	<u>\$ -</u>	<u>\$ 46,311</u>
13	<b>Total Residential and Commercial DSM Costs</b>	\$ 83,434	\$ (2,406)	\$ 81,028		\$ 81,028
14	<b>Projected DSM Under-Recovery 12/31/19*</b>	\$ 4,287	\$ -	\$ 4,287		\$ 4,287
15	<b>Carrying Cost on DSM Under-Recovery</b>	\$ 679	\$ -	\$ 679	\$ (118)	\$ 561
16	<b>Total DSM Tariff Costs</b>	\$ 88,400	\$ (2,406)	\$ 85,994	\$ (118)	\$ 85,877
17	DSM Revenues Included in Current Tariffs	\$ 74,090	\$ (68)	\$ 74,022		\$ 74,022
18	<b>DSM Tariff Increases Before Tax</b>	\$ 14,310	\$ (2,338)	\$ 11,973	\$ (118)	\$ 11,855
19	Federal and State Income Taxes	\$ 3,620	\$ (591)	\$ 3,029	\$ (30)	\$ 2,999
20	DSM Tariff Increases After Tax	\$ 10,690	\$ (1,746)	\$ 8,944	\$ (88)	\$ 8,856
21	Income Expansion Factor	74.602%		74.602%		74.616%*
22	<b>DSM Tariff Increase</b>	<u>\$ 14,330</u>		<u>\$ 11,989</u>		<u>\$ 11,869</u>

Notes and Source:

Col. A: Company Exhibit (DPP/SPA/MBR-1, Schedule 4)  
Cols. B-C: Company Exhibit (DPP/SPA/MBR-1, Schedule 4 DSM Errata)  
Cols. D: See page 8  
Col. E: Sum of columns C-D

\* See page 16

Georgia Power Company  
Demand Side Management (DSM) Tariffs - Staff Calculation  
Retail Electric Amounts

Exhibit (RS/RT-4)  
Page 5 of 17

Calendar 2020  
(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Staff Adjustment to Carrying Costs (D)	Staff Adjusted (E)
<b>Residential Programs</b>						
1	Incentive Costs	\$ 9,508	\$ 422	\$ 9,930		\$ 9,930
2	Non-Incentive Costs	\$ 9,227	\$ 652	\$ 9,880		\$ 9,880
3	Cross-Cutting Costs	\$ 1,725	\$ -	\$ 1,725		\$ 1,725
4	Additional Sum	\$ 3,319	\$ (2,668)	\$ 651		\$ 651
5	Previously-Certified Program Costs & Other DSM	\$ 12,244	\$ 287	\$ 12,531		\$ 12,531
6	<b>Residential Sub-total</b>	<u>\$ 36,023</u>	<u>\$ (1,306)</u>	<u>\$ 34,717</u>	<u>\$ -</u>	<u>\$ 34,717</u>
<b>Commercial Programs</b>						
7	Incentive Costs	\$ 13,568	\$ 321	\$ 13,889		\$ 13,889
8	Non-Incentive Costs	\$ 17,293	\$ 314	\$ 17,607		\$ 17,607
9	Cross-Cutting Costs	\$ 1,725	\$ -	\$ 1,725		\$ 1,725
10	Additional Sum	\$ 11,691	\$ (1,199)	\$ 10,492		\$ 10,492
11	Previously-Certified Program Costs & Other DSM	\$ 3,136	\$ (536)	\$ 2,600		\$ 2,600
12	<b>Commercial Sub-total</b>	<u>\$ 47,411</u>	<u>\$ (1,100)</u>	<u>\$ 46,311</u>	<u>\$ -</u>	<u>\$ 46,311</u>
13	<b>Total Residential and Commercial DSM Costs</b>	\$ 83,434	\$ (2,406)	\$ 81,028		\$ 81,028
14	<b>Projected DSM Under-Recovery 12/31/19*</b>	\$ 4,287	\$ -	\$ 4,287		\$ 4,287
15	<b>Carrying Cost on DSM Under-Recovery</b>	\$ 679	\$ -	\$ 679	\$ (118)	\$ 561
16	<b>Total DSM Tariff Costs</b>	\$ 88,400	\$ (2,406)	\$ 85,994	\$ (118)	\$ 85,877
17	DSM Revenues Included in Current Tariffs	\$ 74,044	\$ (68)	\$ 73,976		\$ 73,976
18	<b>DSM Tariff Increases Before Tax</b>	\$ 14,356	\$ (2,338)	\$ 12,019	\$ (118)	\$ 11,901
19	Federal and State Income Taxes	\$ 3,632	\$ (591)	\$ 3,040	\$ (30)	\$ 3,010
20	DSM Tariff Increases After Tax	\$ 10,725	\$ (1,746)	\$ 8,978	\$ (88)	\$ 8,890
21	Income Expansion Factor	74.596%		74.596%		74.615%*
22	<b>DSM Tariff Increase</b>	<u>\$ 14,377</u>		<u>\$ 12,036</u>		<u>\$ 11,915</u>

Notes and Source:

Col. A: Company Exhibit (DPP/SPA/MBR-1, Schedule 4)  
Cols. B-C: Company Exhibit (DPP/SPA/MBR-1, Schedule 4 DSM Errata)  
Cols. D: See page 8  
Col. E: Sum of columns C-D

\* See page 17



Georgia Power Company  
Demand Side Management (DSM) Tariffs - Staff Calculation  
Retail Electric Amounts

Exhibit (RS/RT-4)  
Page 6 of 17

Calendar 2021  
(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Staff Adjustment to Carrying Costs (D)	Staff Adjusted (E)
<b>Residential Programs</b>						
1	Incentive Costs	\$ 9,717	\$ 413	\$ 10,130		\$ 10,130
2	Non-Incentive Costs	\$ 9,912	\$ 648	\$ 10,560		\$ 10,560
3	Cross-Cutting Costs	\$ 1,619	\$ -	\$ 1,619		\$ 1,619
4	Additional Sum	\$ 3,319	\$ (2,682)	\$ 637		\$ 637
5	Previously-Certified Program Costs & Other DSM	\$ 12,436	\$ 64	\$ 12,500		\$ 12,500
6	<b>Residential Sub-total</b>	<u>\$ 37,003</u>	<u>\$ (1,557)</u>	<u>\$ 35,446</u>	<u>\$ -</u>	<u>\$ 35,446</u>
<b>Commercial Programs</b>						
7	Incentive Costs	\$ 13,858	\$ 89	\$ 13,947		\$ 13,947
8	Non-Incentive Costs	\$ 18,364	\$ 33	\$ 18,398		\$ 18,398
9	Cross-Cutting Costs	\$ 1,619	\$ -	\$ 1,619		\$ 1,619
10	Additional Sum	\$ 11,686	\$ (1,257)	\$ 10,430		\$ 10,430
11	Previously-Certified Program Costs & Other DSM	\$ 3,205	\$ (605)	\$ 2,600		\$ 2,600
12	<b>Commercial Sub-total</b>	<u>\$ 48,732</u>	<u>\$ (1,739)</u>	<u>\$ 46,993</u>	<u>\$ -</u>	<u>\$ 46,993</u>
13	<b>Total Residential and Commercial DSM Costs</b>	\$ 85,735	\$ (3,296)	\$ 82,439		\$ 82,439
14	<b>Projected DSM Under-Recovery 12/31/19*</b>	\$ 4,287	\$ -	\$ 4,287		\$ 4,287
15	<b>Carrying Cost on DSM Under-Recovery</b>	\$ 355	\$ -	\$ 355	\$ (63)	\$ 292
16	<b>Total DSM Tariff Costs</b>	\$ 90,377	\$ (3,296)	\$ 87,081	\$ (63)	\$ 87,017
17	DSM Revenues Included in Current Tariffs	\$ 73,987	\$ (125)	\$ 73,862		\$ 73,862
18	<b>DSM Tariff Increases Before Tax</b>	\$ 16,390	\$ (3,172)	\$ 13,218	\$ (63)	\$ 13,155
19	Federal and State Income Taxes	\$ 4,146	\$ (802)	\$ 3,344	\$ (16)	\$ 3,328
20	DSM Tariff Increases After Tax	\$ 12,244	\$ (2,369)	\$ 9,875	\$ (47)	\$ 9,827
21	Income Expansion Factor	74.597%		74.597%		74.616% *
22	<b>DSM Tariff Increase</b>	<u>\$ 16,414</u>		<u>\$ 13,237</u>		<u>\$ 13,171</u>

Notes and Source:

Col. A: Company Exhibit (DPP/SPA/MBR-1, Schedule 4)  
Cols. B-C: Company Exhibit (DPP/SPA/MBR-1, Schedule 4 DSM Errata)  
Cols. D: See page 8  
Col. E: Sum of columns C-D

\* See page 17

Georgia Power Company  
Demand Side Management (DSM) Tariffs - Staff Calculation  
Retail Electric Amounts

Exhibit \_\_ (RS/RT-4)  
Page 7 of 17

Calendar 2022  
(Thousands of Dollars)

Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Staff Adjustment to Carrying Costs (D)	Staff Adjusted (E)
<b>Residential Programs</b>						
1	Incentive Costs	\$ 9,931	\$ 414	\$ 10,345		\$ 10,345
2	Non-Incentive Costs	\$ 10,054	\$ 647	\$ 10,700		\$ 10,700
3	Cross-Cutting Costs	\$ 1,558	\$ -	\$ 1,558		\$ 1,558
4	Additional Sum	\$ 3,319	\$ (2,694)	\$ 625		\$ 625
5	Previously-Certified Program Costs & Other DSM	\$ 12,640	\$ (163)	\$ 12,477		\$ 12,477
6	<b>Residential Sub-total</b>	<u>\$ 37,503</u>	<u>\$ (1,796)</u>	<u>\$ 35,706</u>	<u>\$ -</u>	<u>\$ 35,706</u>
<b>Commercial Programs</b>						
7	Incentive Costs	\$ 14,128	\$ 119	\$ 14,247		\$ 14,247
8	Non-Incentive Costs	\$ 18,618	\$ 63	\$ 18,681		\$ 18,681
9	Cross-Cutting Costs	\$ 1,558	\$ -	\$ 1,558		\$ 1,558
10	Additional Sum	\$ 11,666	\$ (1,290)	\$ 10,376		\$ 10,376
11	Previously-Certified Program Costs & Other DSM	\$ 3,275	\$ (675)	\$ 2,600		\$ 2,600
12	<b>Commercial Sub-total</b>	<u>\$ 49,245</u>	<u>\$ (1,783)</u>	<u>\$ 47,462</u>	<u>\$ -</u>	<u>\$ 47,462</u>
13	<b>Total Residential and Commercial DSM Costs</b>	\$ 86,748	\$ (3,579)	\$ 83,169		\$ 83,169
14	<b>Projected DSM Under-Recovery 12/31/19*</b>	\$ 4,287	\$ -	\$ 4,287		\$ 4,287
15	<b>Carrying Cost on DSM Under-Recovery</b>	\$ 28	\$ -	\$ 28	\$ (5)	\$ 23
16	<b>Total DSM Tariff Costs</b>	\$ 91,063	\$ (3,579)	\$ 87,483	\$ (5)	\$ 87,478
17	DSM Revenues Included in Current Tariffs	\$ 73,686	\$ (180)	\$ 73,506		\$ 73,506
18	<b>DSM Tariff Increases Before Tax</b>	\$ 17,376	\$ (3,399)	\$ 13,977	\$ (5)	\$ 13,972
19	Federal and State Income Taxes	\$ 4,396	\$ (860)	\$ 3,536	\$ (1)	\$ 3,534
20	DSM Tariff Increases After Tax	\$ 12,981	\$ (2,539)	\$ 10,441	\$ (4)	\$ 10,438
21	Income Expansion Factor	74.598%		74.598%		74.617% *
22	<b>DSM Tariff Increase</b>	<u>\$ 17,401</u>		<u>\$ 13,997</u>		<u>\$ 13,988</u>

Notes and Source:

Col. A: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 4)  
Cols. B-C: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 4 DSM Errata)  
Cols. D: See page 8  
Col. E: Sum of columns C-D

\* See page 17

Georgia Power Company  
Adjustment to Carrying Costs Summary

Exhibit (RS/RT-4)  
Page 8 of 17

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)	Reference
1	DSM Carrying Costs Per Company	\$ 679	\$ 679	\$ 355	\$ 28	A
2	DSM Carrying Costs Per Staff	\$ 561	\$ 561	\$ 292	\$ 23	B
3	Staff Adjustment to Carrying Costs	\$ (118)	\$ (118)	\$ (63)	\$ (5)	

Notes and Source

A: See pages 9 and 10  
B: See pages 11 and 12

**Notes and Source**  
Amounts from the response to STF-PIA-13-3

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Carrying Cost Calculation	2019 August	2019 September	2019 October	2019 November	2019 December	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	Normalization Adjustment	Total Carrying Cost
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)		
1	Beg Pre-Tax Balance	\$ 2,906,308	\$ 2,256,787	\$ 1,588,341	\$ 617,301	\$ (2,130,068)	\$ (3,693,289)	\$ (3,008,202)	\$ (2,390,295)	\$ (1,968,670)	\$ (2,568,403)	\$ (2,213,090)	\$ (2,055,737)		\$ (2,055,737)
2	ADITs	\$ (735,180)	\$ (570,877)	\$ (401,787)	\$ (156,153)	\$ 538,822	\$ 934,254	\$ 760,955	\$ 604,649	\$ 497,995	\$ 649,703	\$ 559,823	\$ 520,019		\$ (520,019)
3	Beg Net-Tax Balance	\$ 2,171,128	\$ 1,685,910	\$ 1,186,554	\$ 461,149	\$ (1,591,246)	\$ (2,759,035)	\$ (2,247,247)	\$ (1,785,646)	\$ (1,470,675)	\$ (1,918,700)	\$ (1,653,266)	\$ (1,535,718)		\$ (1,535,718)
4	Annual Revenue Requirement Rate	9.92%	9.92%	9.92%	9.92%	9.92%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%		10.07%
5	Annual Carrying Cost	\$ 215,377	\$ 167,243	\$ 117,707	\$ 45,746	\$ (157,852)	\$ (277,932)	\$ (226,377)	\$ (179,877)	\$ (148,149)	\$ (193,280)	\$ (166,542)	\$ (154,701)		\$ (154,701)
6	Number of Days in Year	365	365	365	365	365	365	366	366	366	366	366	366		366
7	Daily Carrying Cost	\$ 590	\$ 458	\$ 322	\$ 125	\$ (432)	\$ (759)	\$ (619)	\$ (491)	\$ (405)	\$ (528)	\$ (455)	\$ (423)		\$ (423)
8	Number of Days in Month	31	30	31	30	31	31	29	31	30	31	30	31		31
9	Current Month Carrying Cost	\$ 18,292	\$ 13,746	\$ 9,997	\$ 3,760	\$ (13,407)	\$ (23,541)	\$ (17,937)	\$ (15,256)	\$ (12,143)	\$ (16,371)	\$ (13,651)	\$ (13,103)	\$ 65,296	\$ (144,890)
10	Beg Pre-Tax Balance	\$ (3,693,289)	\$ (2,390,295)	\$ (2,390,295)	\$ (1,968,670)	\$ (2,568,403)	\$ (2,213,090)	\$ (2,055,737)	\$ (1,468,070)	\$ (881,802)	\$ (463,766)	\$ (400,757)	\$ (1,989,991)		\$ (1,989,991)
11	ADITs	\$ 934,254	\$ 760,955	\$ 604,649	\$ 497,995	\$ 649,703	\$ 559,823	\$ 520,019	\$ 371,363	\$ 223,061	\$ 117,314	\$ 101,375	\$ 503,388		\$ 503,388
12	Beg Net-Tax Balance	\$ (2,759,035)	\$ (2,247,247)	\$ (1,785,646)	\$ (1,470,675)	\$ (1,918,700)	\$ (1,653,266)	\$ (1,535,718)	\$ (1,096,707)	\$ (658,742)	\$ (346,451)	\$ (299,381)	\$ (1,486,603)		\$ (1,486,603)
13	Annual Revenue Requirement Rate	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%		10.07%
14	Annual Carrying Cost	\$ (277,932)	\$ (226,377)	\$ (179,877)	\$ (148,149)	\$ (193,280)	\$ (166,542)	\$ (154,701)	\$ (110,477)	\$ (66,358)	\$ (34,900)	\$ (30,158)	\$ (149,753)		\$ (149,753)
15	Number of Days in Year	366	366	366	366	366	366	366	366	366	366	366	366		366
16	Daily Carrying Cost	\$ (759)	\$ (619)	\$ (491)	\$ (405)	\$ (528)	\$ (455)	\$ (423)	\$ (302)	\$ (181)	\$ (95)	\$ (82)	\$ (409)		\$ (409)
17	Number of Days in Month	31	29	31	30	31	30	31	31	30	31	30	31		31
18	Current Month Carrying Cost	\$ (23,541)	\$ (17,937)	\$ (15,256)	\$ (12,143)	\$ (16,371)	\$ (13,651)	\$ (13,103)	\$ (9,357)	\$ (6,439)	\$ (2,956)	\$ (2,472)	\$ (12,684)	\$	\$ (144,890)
19	Beg Pre-Tax Balance	\$ (2,462,193)	\$ (1,760,711)	\$ (1,126,923)	\$ (695,424)	\$ (1,131,775)	\$ (951,591)	\$ (793,890)	\$ (194,809)	\$ 402,862	\$ 829,124	\$ 891,728	\$ (743,580)		\$ (743,580)
20	ADITs	\$ 622,836	\$ 445,389	\$ 285,066	\$ 175,914	\$ 332,333	\$ 240,714	\$ 200,822	\$ 49,279	\$ (101,908)	\$ (209,735)	\$ (325,572)	\$ 188,096		\$ 188,096
21	Beg Net-Tax Balance	\$ (1,839,356)	\$ (1,315,321)	\$ (841,857)	\$ (519,509)	\$ (981,443)	\$ (710,876)	\$ (593,068)	\$ (145,530)	\$ 300,954	\$ 619,389	\$ 666,157	\$ (555,484)		\$ (555,484)
22	Annual Revenue Requirement Rate	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%		10.16%
23	Annual Carrying Cost	\$ (186,943)	\$ (133,683)	\$ (85,562)	\$ (52,800)	\$ (99,749)	\$ (72,250)	\$ (60,276)	\$ (14,791)	\$ 30,587	\$ 62,952	\$ 67,705	\$ (36,457)		\$ (36,457)
24	Number of Days in Year	365	365	365	365	365	365	365	365	365	365	365	365		365
25	Daily Carrying Cost	\$ (512)	\$ (366)	\$ (234)	\$ (145)	\$ (273)	\$ (198)	\$ (165)	\$ (41)	\$ 84	\$ 172	\$ 185	\$ (135)		\$ (135)
26	Number of Days in Month	31	28	31	30	31	30	31	31	30	31	30	31		31
27	Current Month Carrying Cost	\$ (15,877)	\$ (10,255)	\$ (7,267)	\$ (4,340)	\$ (8,472)	\$ (5,938)	\$ (5,119)	\$ (1,256)	\$ 2,514	\$ 5,347	\$ 5,565	\$ (4,795)	\$	\$ (49,893)
28	Beg Pre-Tax Balance	\$ (1,231,096)	\$ (523,086)	\$ 116,965	\$ 552,785	\$ (72,392)	\$ 292,466	\$ 449,821	\$ 1,052,509	\$ 1,653,785	\$ 2,083,020	\$ 2,145,820	\$ 493,059		\$ 493,059
29	ADITs	\$ 311,418	\$ 132,320	\$ (29,587)	\$ (139,832)	\$ 18,312	\$ (73,982)	\$ (113,787)	\$ (266,243)	\$ (418,341)	\$ (526,921)	\$ (542,807)	\$ (124,724)		\$ (124,724)
30	Beg Net-Tax Balance	\$ (919,678)	\$ (390,766)	\$ 87,378	\$ 412,952	\$ (54,080)	\$ 218,484	\$ 336,034	\$ 786,266	\$ 1,235,443	\$ 1,556,099	\$ 1,603,013	\$ 368,335		\$ 368,335
31	Annual Revenue Requirement Rate	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%		10.21%
32	Annual Carrying Cost	\$ (93,931)	\$ (39,911)	\$ 8,924	\$ 42,177	\$ (5,523)	\$ 22,315	\$ 34,321	\$ 80,305	\$ 126,181	\$ 158,931	\$ 163,723	\$ 37,620		\$ 37,620
33	Number of Days in Year	365	365	365	365	365	365	365	365	365	365	365	365		365
34	Daily Carrying Cost	\$ (257)	\$ (109)	\$ 24	\$ 116	\$ (15)	\$ 61	\$ 94	\$ 220	\$ 346	\$ 435	\$ 449	\$ 103		\$ 103
35	Number of Days in Month	31	28	31	31	30	31	31	31	30	31	30	31		31
36	Current Month Carrying Cost	\$ (7,978)	\$ (3,062)	\$ 758	\$ 3,467	\$ (469)	\$ 1,834	\$ 2,915	\$ 6,820	\$ 10,371	\$ 13,498	\$ 13,457	\$ 3,195	\$	\$ 44,806

Notes and Source

Amounts from the response to STP-PIA-13-3

Notes and Source  
Amounts from the response to STT-P(A)-13-3 except where noted below.  
Line 4, columns F-L: see page 13  
Line 13: see page 13  
Line 22: see page 14  
Line 31: see page 15

Notes and Source  
Amounts from the response to STF-PIA-13-3 except where noted below.  
Line 4, columns F-L: see page 13  
Line 13: see page 13  
Line 22: see page 14  
Line 31: see page 15

Georgia Power Company  
Capital Structure & Cost Rates

Exhibit (RS/RT-4)  
Page 13 of 17

Calendar 2020  
(Thousands of Dollars)

Line No.	Capital Source	Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)	After-Tax Rate (E)	Pre-Tax Rate (F)	Revenue Requirement Ratio (G)	Revenue Requirement Rate (H)
<b>I. Company - Proposed</b>									
1	Long-Term Debt	\$ 12,183,077	43.98%	4.26%	1.88%	1.40%	1.88%		
2	Common Stock Equity	\$ 15,515,922	56.02%	10.90%	6.11%	6.11%	8.17%		
3	Total Capital	\$ 27,699,000	100.00%		7.98%	7.51%	10.05%	1.00145681	10.06%
<b>II. Staff - Proposed</b>									
4	Long-Term Debt		49.00%	4.15%	2.03%	1.52%	2.03%		
5	Common Stock Equity		51.00%	9.20%	4.69%	4.69%	6.28%		
6	Total Capital		100.00%		6.73%	6.21%	8.31%	1.0011942	8.32%
7	Difference				-1.2561%				
8	Weighted Cost of Debt				2.03%				

Notes and Source

The amounts shown in Cols A-F are also presented on Exhibit (RS/RT-2), Schedule D, page 2

Lines 1-3: Company Exhibit (DPP/SPA/MBR-3, Schedule 2, Workpaper 2)

Lines 4-8: Sponsored by Staff witness Michael Gorman

Col. G: see page 17

Col. H: Col. F x Col. G



Georgia Power Company  
Capital Structure & Cost Rates

Exhibit (RS/RT-4)  
Page 14 of 17

Calendar 2021  
(Thousands of Dollars)

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)	After-Tax Rate (E)	Pre-Tax Rate (F)	Revenue Requirement Ratio (G)	Revenue Requirement Rate (H)
<b>I. Company - Proposed</b>									
1	Long-Term Debt	\$ 13,180,823	43.97%	4.47%	1.97%	1.47%	1.97%		
2	Common Stock Equity	\$ 16,793,575	56.03%	10.90%	6.11%	6.11%	8.17%		
3	Total Capital	\$ 29,974,398	100.00%		8.07%	7.58%	10.14%	1.00144253	10.16%
<b>II. Staff - Proposed</b>									
4	Long-Term Debt		49.00%	4.21%	2.06%	1.54%	2.06%		
5	Common Stock Equity		51.00%	9.20%	4.69%	4.69%	6.28%		
6	Total Capital		100.00%		6.75%	6.23%	8.34%	1.00118197	8.35%
7	Difference				-1.3186%				
8	Weighted Cost of Debt				2.06%				

Notes and Source

The amounts shown in Cols A-F are also presented on Exhibit (RS/RT-2), Schedule D, page 3

Lines 1-3: Company Exhibit (DPP/SPA/MBR-3, Schedule 2, Workpaper 2)

Lines 4-8: Sponsored by Staff witness Michael Gorman

Col. G: see page 17

Col. H: Col. F x Col. G

Georgia Power Company  
Capital Structure & Cost Rates

Exhibit (RS/RT-4)  
Page 15 of 17

Calendar 2022  
(Thousands of Dollars)

Line No.	Capital Source	Capitalization		Cost Rate (C)	Weighted Avg. Cost of Capital (D)	After-Tax Rate (E)	Pre-Tax Rate (F)	Requirement Ratio (G)	Requirement Rate (H)
		Amount (A)	Percent (B)						
I. Company - Proposed									
1	Long-Term Debt	\$ 14,105,627	43.97%	4.60%	2.02%	1.51%	2.02%		
2	Common Stock Equity	\$ 17,972,984	56.03%	10.90%	6.11%	6.11%	8.17%		
3	Total Capital	\$ 32,078,610	100.00%		8.13%	7.62%	10.20%	1.00143097	10.21%
II. Staff - Proposed									
4	Long-Term Debt		49.00%	4.19%	2.05%	1.53%	2.05%		
5	Common Stock Equity		51.00%	9.20%	4.69%	4.69%	6.28%		
6	Total Capital		100.00%		6.75%	6.23%	8.33%	1.00117207	8.34%
7	Difference				-1.3851%				
8	Weighted Cost of Debt				2.05%				

Notes and Source

The amounts shown in Cols A-F are also presented on Exhibit (RS/RT-2), Schedule D, page 4

Lines 1-3: Company Exhibit (DPP/SPA/MBR-3, Schedule 2, Workpaper 2)

Lines 4-8: Sponsored by Staff witness Michael Gorman

Col. G: see page 17

Col. H: Col. F x Col. G

Georgia Power Company  
Computation of Gross Revenue Conversion Factor

Exhibit \_\_ (RS/RT-4)  
Page 16 of 17

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Income Taxes (A)	Company Proposed (B)	Staff Proposed (C)
1	Gross Revenue		100.000%	100.00%
2	Less: Federal and State Income Taxes	25.296%	25.296%	25.296%
3	Net Revenue After Income Taxes		74.704%	74.704%
<b>Less: Uncollectibles</b>				
4	Estimated Uncollectibles		\$ 13,445	\$ 12,000
5	Retail Revenue (Excluding Street & Hwy Lighting)		\$ 7,691,172	\$ 7,691,172
6	Uncollectible Accounts (Before Income Taxes)		0.175%	0.156%
7	Less: Federal and State Income Taxes	25.296%	0.044%	0.039%
8	Net Effect of Uncollectible Accounts		0.131%	0.117%
<b>Add: Additional Compensation for Collecting State Sales Taxes</b>				
9	Estimated Sales Tax Percentage		7.519%	7.519%
10	Collection Fee Received		0.500%	0.500%
11	Additional Compensation (Before Income Taxes)		0.038%	0.038%
12	Less: Federal and State Income Taxes	25.296%	0.010%	0.010%
13	Net Effect of Uncollectible Accounts		0.028%	0.028%
14	After Tax Effect of Additional Revenue (Income Expansion Factor)		74.602%	74.616%
15	Gross Revenue Conversion Factor		1,340,447	1,340,195

Notes and Source

The amounts shown above are also presented on Exhibit \_\_ (RS/RT-2), Schedule A-1, page 1  
Col.B: Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 2 of 10  
Col.C: Staff proposed

Georgia Power Company  
Computation of Gross Revenue Conversion Factor

Exhibit \_\_ (RS/RT-4)  
Page 17 of 17

(Thousands of Dollars)

Line No.	Description	Income Taxes (A)	Calendar 2020		Calendar 2021		Calendar 2022	
			Company Proposed (B)	Staff Proposed (C)	Company Proposed (D)	Staff Proposed (E)	Company Proposed (F)	Staff Proposed (G)
1	Gross Revenue		100.000%	100.000%	100.00%	100.000%	100.00%	100.000%
2	Less: Federal and State Income Taxes	25.296%	25.296%	25.296%	25.296%	25.296%	25.296%	25.296%
3	Net Revenue After Income Taxes		<u>74.704%</u>	<u>74.704%</u>	<u>74.704%</u>	<u>74.704%</u>	<u>74.704%</u>	<u>74.704%</u>
<b>Less: Uncollectibles</b>								
4	Estimated Uncollectibles		\$ 14,003	\$ 12,000	\$ 14,003	\$ 12,000	\$ 14,004	\$ 12,000
5	Retail Revenue (Excluding Street & Hwy Lighting)		<u>\$ 7,649,528</u>	<u>\$7,649,528</u>	<u>\$ 7,709,482</u>	<u>\$ 7,709,482</u>	<u>\$ 7,758,733</u>	<u>\$7,758,733</u>
6	Uncollectible Accounts (Before Income Taxes)		0.183%	0.157%	0.182%	0.156%	0.180%	0.155%
7	Less: Federal and State Income Taxes	25.296%	0.046%	0.040%	0.046%	0.039%	0.046%	0.039%
8	Net Effect of Uncollectible Accounts		<u>0.137%</u>	<u>0.117%</u>	<u>0.136%</u>	<u>0.116%</u>	<u>0.135%</u>	<u>0.116%</u>
<b>Add: Additional Compensation for Collecting State Sales Taxes</b>								
9	Estimated Sales Tax Percentage		7.519%	7.519%	7.519%	7.519%	7.519%	7.519%
10	Collection Fee Received		<u>0.500%</u>	<u>0.500%</u>	<u>0.500%</u>	<u>0.500%</u>	<u>0.500%</u>	<u>0.500%</u>
11	Additional Compensation (Before Income Taxes)		0.038%	0.038%	0.038%	0.038%	0.038%	0.038%
12	Less: Federal and State Income Taxes	25.296%	0.010%	0.010%	0.010%	0.010%	0.010%	0.010%
13	Net Effect of Uncollectible Accounts		<u>0.028%</u>	<u>0.028%</u>	<u>0.028%</u>	<u>0.028%</u>	<u>0.028%</u>	<u>0.028%</u>
14	After Tax Effect of Additional Revenue (Income Expansion Factor)		<u>74.596%</u>	<u>74.615%</u>	<u>74.597%</u>	<u>74.616%</u>	<u>74.598%</u>	<u>74.617%</u>
15	Gross Revenue Conversion Factor		<u>1.340558</u>	<u>1.340206</u>	<u>1.340539</u>	<u>1.340190</u>	<u>1.340523</u>	<u>1.340177</u>

Notes and Source

The amounts shown above are also presented on Exhibit \_\_ (RS/RT-2), Schedule A-1, page 2  
Cols. B, D & F; Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), page 2 of 10  
Cols. C, E and G; Staff proposed

16	One divided by Net Revenue After Taxes - Line 3 above	1.338607595	1.33860759	1.338607595	1.338607595	1.338607595	1.338607595	1.33860759
17	Gross Revenue Conversion Factor (Line 15) Divided by Line 16	1.001456807	1.0011942	1.00144253	1.001181973	1.001430967	1.001430967	1.00117207

EXHIBIT\_\_(RS/RT-5)

Georgia Power Company  
Docket No. 42516  
Staff Exhibit \_\_ (RS/RT-5)  
Municipal Franchise Fees (MFF) Tariff Adjustment Schedules  
Accompanying the Direct Testimony of Ralph C. Smith and Robert Trokey

Description	Primary Staff Witnesses	Confidential	No. of Pages	Page No.
Revenue Requirement Summary Schedules				
Computation of MFF Adjustment	R. Smith/R. Trokey	No	3	2-4
Total Pages, Including Content Listing			4	

Georgia Power Company

Municipal Franchise Fees (MFF) Tariff

Retail Electric Amounts

(Thousand of Dollars)

Exhibit\_\_(RS/RT-5)

Page 2 of 4

Line No.	Description	Test Period		
		2020	2021	2022
1	Total MFF Revenue Deficiency - Per Company	\$ 16,802	\$ 20,035	\$ 25,369
2	Total MFF Revenue Deficiency - Per Staff	\$ 10,537	\$ 20,138	\$ 32,055
3	MFF Revenue Adjustment	\$ (6,265)	\$ 103	\$ 6,686

Notes and Source:

Line 1: Company Exhibit\_\_(DPP/SPA/MBR-1, Schedule 5)

Line 2: Page 3

Georgia Power Company  
Municipal Franchise Fees (MFF) Tariff - Company Calculation  
Retail Electric Amounts  
(Thousand of Dollars)

Exhibit \_\_ (RS/RT-5)  
Page 3 of 4

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
<u>MFF Expenses</u>					
1	Total Budgeted Revenue Before MFF	\$ 7,596,602	\$ 7,556,340	\$ 7,617,219	\$ 7,657,253
2	% of Revenues Inside Municipalities	× 62.36%	62.36%	62.36%	62.36%
3	Revenues Inside Municipalities	\$ 4,737,521	\$ 4,712,412	\$ 4,750,378	\$ 4,775,345
4	MFF Rate	× 4.00%	4.00%	4.00%	4.00%
5	MFF Expenses	\$ 189,501	\$ 188,496	\$ 190,015	\$ 191,014
<u>Carrying Charge on Pro Forma Average MFF Working Capital</u>					
6	MFF Expenses	\$ 189,501	\$ 188,496	\$ 190,015	\$ 191,014
7	Calendar Year Days	÷ 366	366	365	365
8	Average Daily MFF Expenses	\$ 518	\$ 515	\$ 521	\$ 523
9	MFF Net Lead Days	× (201.1)	(201.1)	(201.1)	(201.1)
10	Average MFF Working Capital	\$ (104,102)	\$ (103,550)	\$ (104,670)	\$ (105,221)
11	Pre-Tax Weighted Average Cost of Capital	× 10.00%	10.05%	10.14%	10.20%
12	Carrying Charge on Pro Forma Average MFF Working Capital	\$ (10,413)	\$ (10,406)	\$ (10,615)	\$ (10,730)
<u>MFF Rate</u>					
13	Adjusted MFF Expenses	\$ 179,088	\$ 178,091	\$ 179,400	\$ 180,283
14	Total Budgeted Revenue Before MFF	÷ 7,596,602	7,556,340	7,617,219	7,657,253
15	MFF Rate	2.36%	2.36%	2.36%	2.35%
<u>MFF Revenue Deficiency</u>					
16	New MFF Rate	2.36%	2.36%	2.36%	2.35%
17	Current MFF Rate	- 2.30%	2.30%	2.30%	2.30%
18	MFF Rate Increase	0.05%	0.05%	0.05%	0.05%
19	Total Budgeted Revenue Before MFF	× 7,596,602	7,556,340	7,617,219	7,657,253
20	MFF Deficiency on Existing Revenue	\$ 3,988	\$ 3,919	\$ 3,825	\$ 3,785
21	Traditional Base Revenue Deficiency	\$ 7,309	\$ 367,334	\$ 506,943	\$ 734,409
22	New MFF Rate	× 2.36%	2.36%	2.36%	2.35%
23	Incremental MFF Revenue Requirement on Traditional Base Revenue Deficiency	\$ 172	\$ 8,657	\$ 11,939	\$ 17,291
24	ECCR Revenue Deficiency	\$ 173,625	\$ 164,926	\$ 164,926	\$ 164,926
25	New MFF Rate	× 2.36%	2.36%	2.36%	2.35%
26	Incremental MFF Revenue Requirement on ECCR Revenue Deficiency	\$ 4,093	\$ 3,887	\$ 3,884	\$ 3,883
27	DSM Revenue Deficiency	\$ 14,330	\$ 14,377	\$ 16,414	\$ 17,401
28	New MFF Rate	× 2.36%	2.36%	2.36%	2.35%
29	Incremental MFF Revenue Requirement on DSM Revenue Deficiency	\$ 338	\$ 339	\$ 387	\$ 410
30	Total MFF Revenue Deficiency	\$ 8,591	\$ 16,802	\$ 20,035	\$ 25,369
31	MFF Tariff Incremental Increase/(Decrease)		\$ 16,802	\$ 3,233	\$ 5,334

Note: Details may not add to totals due to rounding.

- (a) 235.8 Expense Lead Days Net of 34.7 Retail Revenue Lag Days  
(b) From Exhibit \_\_ (DPP/SPA/MBR-3, Schedule 2, Workpapers 1-4)  
(c) As approved in the 2016 Compliance filing in Docket No. 36989  
(d) From Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 2 Traditional Base) - also see lines 32-40 below  
(e) From Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 3 ECCR)  
(f) From Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 4 DSM)

#### Notes and Source:

Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 5)

Amounts below from Exhibit __ (DPP/SPA/MBR-1, Schedule 2 Traditional Base):		Test Period			
32	Total Revenue Deficiency Excluding MFF	\$ 195,263			
33	Less: ECCR Revenue Deficiency	\$ (173,625)			
34	Less: DSM Revenue Deficiency	\$ (14,330)			
35	Revenue Deficiency Applicable to Traditional Base Rate Tariffs	\$ 7,309			
			2020	2021	2022
36	Levelized Revenue Deficiency Applicable to Traditional Base Rate Tariffs Less CCR ARO Compliance		\$ 209,224	\$ 139,610	\$ 227,466
37	2020 Revenue Deficiency Applicable to Traditional Base Rate Tariffs for CCR ARO Compliance		\$ 158,110	\$ 367,334	\$ 506,943
38	Revenue Deficiency Applicable to Traditional Base Rate Tariffs		\$ 367,334	\$ 506,943	\$ 734,409
39	CCR ARO Compliance Revenue Requirement		\$ 158,110	\$ 297,719	\$ 525,186
				\$ (158,110)	\$ (297,719)
40	CCR ARO Compliance Incremental Increase		\$ 158,110	\$ 139,610	\$ 227,466



Georgia Power Company  
Municipal Franchise Fees (MFF) Tariff - Staff Calculation  
Retail Electric Amounts  
(Thousand of Dollars)

Exhibit \_\_ (RS/RT-5)  
Page 4 of 4

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
<i><u>MFF Expenses</u></i>					
1a	Total Budgeted Revenue Before MFF Per Company	\$ 7,596,602	\$ 7,556,340	\$ 7,617,219	\$ 7,657,253
1b	Staff Adjustments				
	Total Budgeted Revenue Before MFF Staff Adjusted	\$ 7,596,602	\$ 7,556,340	\$ 7,617,219	\$ 7,657,253
2	% of Revenues Inside Municipalities	× 62.36%	62.36%	62.36%	62.36%
3	Revenues Inside Municipalities	\$ 4,737,521	\$ 4,712,412	\$ 4,750,378	\$ 4,775,345
4	MFF Rate	× 4.00%	4.00%	4.00%	4.00%
5	MFF Expenses	\$ 189,501	\$ 188,496	\$ 190,015	\$ 191,014
<i><u>Carrying Charge on Pro Forma Average MFF Working Capital</u></i>					
6	MFF Expenses	\$ 189,501	\$ 188,496	\$ 190,015	\$ 191,014
7	Calendar Year Days	+ 366	366	365	365
8	Average Daily MFF Expenses	\$ 518	\$ 515	\$ 521	\$ 523
9	MFF Net Lead Days	× (201.1)	(201.1)	(201.1)	(201.1) (a)
10	Average MFF Working Capital	\$ (104,102)	\$ (103,550)	\$ (104,670)	\$ (105,221)
11	Pre-Tax Weighted Average Cost of Capital	× 8.28%	8.31%	8.34%	8.33% (b)
12	Carrying Charge on Pro Forma Average MFF Working Capital	\$ (8,615)	\$ (8,609)	\$ (8,733)	\$ (8,769)
<i><u>MFF Rate</u></i>					
13	Adjusted MFF Expenses	\$ 180,886	\$ 179,887	\$ 181,282	\$ 182,245
14	Total Budgeted Revenue Before MFF Per Company	+ 7,596,602	7,556,340	7,617,219	7,657,253
15	MFF Rate	2.38%	2.38%	2.38%	2.38%
<i><u>MFF Revenue Deficiency</u></i>					
16	New MFF Rate	2.38%	2.38%	2.38%	2.38%
17	Current MFF Rate	- 2.30%	2.30%	2.30%	2.30% (c)
18	MFF Rate Increase	0.08%	0.08%	0.07%	0.08%
19	Total Budgeted Revenue Before MFF Per Company	× 7,596,602	7,556,340	7,617,219	7,657,253
20	MFF Deficiency on Existing Revenue	\$ 5,786	\$ 5,715	\$ 5,706	\$ 5,747
21	Traditional Base Revenue Deficiency	\$ (56,521)	\$ 69,543	\$ 486,266	\$ 1,008,686 (d)
22	New MFF Rate	× 2.38%	2.38%	2.38%	2.38%
23	Incremental MFF Revenue Requirement on Traditional Base Revenue Deficiency	\$ (1,346)	\$ 1,656	\$ 11,573	\$ 24,007
24	ECCR Revenue Deficiency	\$ 112,688	\$ 121,090	\$ 106,974	\$ 82,683 (e)
25	New MFF Rate	× 2.38%	2.38%	2.38%	2.38%
26	Incremental MFF Revenue Requirement on ECCR Revenue Deficiency	\$ 2,683	\$ 2,883	\$ 2,546	\$ 1,968
27	DSM Revenue Deficiency	\$ 11,869	\$ 11,915	\$ 13,171	\$ 13,988 (f)
28	New MFF Rate	× 2.38%	2.38%	2.38%	2.38%
29	Incremental MFF Revenue Requirement on DSM Revenue Deficiency	\$ 283	\$ 284	\$ 313	\$ 333
30	Total MFF Revenue Deficiency	\$ 7,406	\$ 10,537	\$ 20,138	\$ 32,055
31	MFF Tariff Incremental Increase/(Decrease)		\$ 10,537	\$ 9,602	\$ 11,916

Note: Details may not add to totals due to rounding.

- (a) 235.8 Expense Lead Days Net of 34.7 Retail Revenue Lag Days  
(b) From Exhibit \_\_ (RS/RT-2), Schedule D  
(c) As approved in the 2016 Compliance filing in Docket No. 36989  
(d) See Lines 32-43 below  
(e) From Exhibit \_\_ (RS/RT-3)  
(f) From Exhibit \_\_ (RS/RT-4)

Notes and Source:

Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 5)

32	Total Revenue Deficiency Excluding MFF - see Exhibit __ (RS/RT-2), Schedule A	Test Period \$ (181,078)			
33	Less: ECCR Revenue Deficiency - see Exhibit __ (RS/RT-3), Page 2	\$ (112,688)			
34	Less: DSM Revenue Deficiency - see Exhibit __ (RS/RT-4), Page 2	\$ (11,869)			
35	Revenue Deficiency Applicable to Traditional Base Rate Tariffs	\$ (56,521)	to Line 21		
36	Base Rate Revenue Deficiency - see below	\$ (35,063)	2020	2021	2022
37	CCR ARO Compliance Revenue Deficiency Applicable to Traditional Base Rate Tariffs - see Exhibit __ (RS/RT-6), Page 3	\$ 104,606	\$ 416,722	\$ 522,420	\$ 522,420
38	Revenue Deficiency Applicable to Traditional Base Rate Tariffs - Test Year and 2020	\$ 69,543	\$ 69,543	\$ 486,266	\$ 1,008,686 to Line 21
39	Base Rate Revenue Deficiency - see Exhibit __ (RS/RT-2), Schedule A	\$ (35,063)	\$ 283,428	\$ 646,685	
40	CCR ARO Compliance Revenue Deficiency Applicable to Traditional Base Rate Tariffs - see Exhibit __ (RS/RT-6), Page 3	\$ 104,606	\$ 202,837	\$ 362,001	
41	Revenue Deficiency Applicable to Traditional Base Rate Tariffs - 2020-2022	\$ 69,543	\$ 486,266	\$ 1,008,686	
42	Less previous year's revenue deficiency		\$ (69,543)	\$ (486,266)	
43	Base Rate Revenue and CCR-ARO Compliance Incremental Increase		\$ 416,722	\$ 522,420	

EXHIBIT\_\_(RS/RT-6)

Georgia Power Company  
Docket No. 42516  
Exhibit \_\_ (RS/RT-6)  
Coal Combustion Residual (CCR) - Asset Retirement Obligation (ARO) Compliance  
Accompanying the Direct Testimony of Ralph C. Smith and Robert Trokey

Description	Primary Staff Witnesses	Confidential	No. of Pages	Page No.
<b>Revenue Requirement Summary Schedules</b>				
Computation of Test Year CCR-ARO Revenue Requirement	R. Smith/R. Trokey	No	1	2
Computation of Plan Years 2020-2022 CCR-ARO Revenue Requirement	R. Smith/R. Trokey	No	1	3
ARO Rate Base and Operating Income Detail Per Company	R. Smith/R. Trokey	No	1	4
Summary of Errata and Staff Adjustments For the Test Year	R. Smith/R. Trokey	Yes	1	5
Summary of Errata and Staff Adjustments for Calendar 2020	R. Smith/R. Trokey	Yes	1	6
Summary of Errata and Staff Adjustments for Calendar 2021	R. Smith/R. Trokey	Yes	1	7
Summary of Errata and Staff Adjustments Calendar 2022	R. Smith/R. Trokey	Yes	1	8
Impacts of the Company's Errata Adjustments With Contingencies Removed	R. Smith/R. Trokey	Yes	1	9
Company Errata Adjustments	R. Smith/R. Trokey	No	1	10
Total Pages, Including Content Listing			10	

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Computation of Test Year CCR-ARO Revenue Requirement

**STAFF - NO RATE BASE EQUITY RETURN  
ALLOW DEBT INTEREST COST ON BALANCES**

Test Year Ended July 31, 2020  
(Thousands of Dollars)

Line No.	Description	Per Company Revenue Deficiency (A)	Per Staff Revenue Deficiency (B)	Difference (C) = (B) - (A)
1	CCR ARO Compliance Retail Rate Base	\$ 152,120	\$ -	\$ (152,120)
2	Requested Rate of Return	7.93%	0.00%	
3	Earnings Requirement	\$ 12,067	\$ -	\$ (12,067)
4	Less: Operating Income Deficiency	<u>\$ (100,800)</u>	<u>\$ (76,531)</u>	<u>\$ 24,269</u>
5	Earnings Deficiency	\$ 112,867	\$ 76,531	\$ (36,336)
6	Income Expansion Factor	74.602%	74.616%	
7	CCR ARO Compliance Revenue Requirement	<u>\$ 151,292</u>	<u>\$ 102,566</u>	<u>\$ (48,726)</u>

Notes and Source

Details may not add to totals due to rounding  
Col. A: Amounts from Company Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 2 Traditional Base), Page 4 of 5  
Col. B, lines 1-3: Staff is not recommending a rate base return on CCR-ARO costs  
Col. B, line 4: See page 5 of 10  
Line 6: See Exhibit \_\_ (RS/RT-2), Schedule A-1, page 1

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Computation of Plan Years 2020-2022 CCR-ARO Revenue Requirement

**STAFF - NO RATE BASE EQUITY RETURN  
ALLOW DEBT INTEREST COST ON BALANCES**

Calendar Years 2020-2022  
(Thousands of Dollars)

Line No.	Description	2020 (A)	2021 (B)	2022 (C)
<b>I. Per Company</b>				
1	CCR ARO Compliance Retail Rate Base	\$ 219,038	\$ 291,986	\$ 375,416
2	Requested Rate of Return	7.98%	8.07%	8.13%
3	Earnings Requirement	\$ 17,483	\$ 23,574	\$ 30,522
4	Less: Operating Income Deficiency	(100,461)	(198,516)	(361,255)
5	Earnings Deficiency	\$ 117,943	\$ 222,089	\$ 391,777
6	Income Expansion Factor	74.596%	74.597%	74.598%
7	CCR ARO Compliance Revenue Requirement	\$ 158,110	\$ 297,719	\$ 525,186
<b>II. Per Staff</b>				
8	CCR ARO Compliance Retail Rate Base	\$ -	\$ -	\$ -
9	Long-Term Debt Interest on Net Deferred Balances	0.00%	0.00%	0.00%
10	Earnings Requirement	\$ -	\$ -	\$ -
11	Less: Operating Income Deficiency	(78,052)	(151,350)	(270,115)
12	Earnings Deficiency	\$ 78,052	\$ 151,350	\$ 270,115
13	Income Expansion Factor	74.615%	74.616%	74.617%
14	CCR ARO Compliance Revenue Requirement	\$ 104,606	\$ 202,837	\$ 362,001
<b>III. Difference Between Staff and Company</b>				
15	CCR ARO Compliance Revenue Requirement	\$ (53,504)	\$ (94,882)	\$ (163,184)

Notes and Source:

Details may not add to totals due to rounding.  
Cols. A-C, Lines 1-7: Amounts from Exhibit (DPP/SPA/MBR-1, Schedule 1 Traditional Base)  
Lines 8-10: Staff is not recommending a rate base return on CCR-ARO costs  
Lines 11: See pages 6 (2020), 7 (2021) and 8 (2022), line 18  
Line 13: See Exhibit (RS/RT-2), Schedule A-1, page 2

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
ARO Rate Base and Operating Income Detail Per Company

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
<b>Per Company</b>					
1	CCR ARO Compliance Regulatory Asset - Beginning Balance		\$ 241,020	\$ 345,391	\$ 436,317
2	CCR ARO Compliance Expenditures	\$ 245,328	\$ 277,068	\$ 395,432	\$ 655,412
3	Amortization of Prior Under Recovery	\$ 80,340	\$ 80,340	\$ 80,340	\$ 80,340
4	1/3 Recovery of 2020 Expenditures	92,356	92,356	92,356	92,356
5	1/3 Recovery of 2021 Expenditures			131,811	131,811
6	1/3 Recovery of 2022 Expenditures				218,471
7	CCR ARO Compliance Recovery	\$ 172,696	\$ 172,696	\$ 304,506	\$ 522,977
8	CCR ARO Compliance Regulatory Asset - Ending Balance		\$ 345,391	\$ 436,317	\$ 568,752
9	CCR ARO Compliance Regulatory Asset (13-Month average)	\$ 203,629	\$ 293,205	\$ 390,854	\$ 502,535
10	Accumulated Deferred Income Taxes	(51,509)	(74,168)	(98,869)	(127,119)
11	CCR ARO Compliance Retail Rate Base	<u>\$ 152,120</u>	<u>\$ 219,038</u>	<u>\$ 291,986</u>	<u>\$ 375,416</u>
<b>Operating Income Deficiency</b>					
12	CCR ARO Compliance Revenues Included in Current Rates	\$ 36,827	\$ 36,827	\$ 36,827	\$ 36,827
13	CCR ARO Compliance Recovery	(172,696)	(172,696)	(304,506)	(522,977)
14	Earnings Before Taxes	\$ (135,869)	\$ (135,869)	\$ (267,679)	\$ (486,150)
15	Federal Income Taxes	27,531	27,797	54,296	98,049
16	State Income Taxes	7,538	7,611	14,867	26,847
17	<b>Operating Income Deficiency</b>	<u>\$ (100,800)</u>	<u>\$ (100,461)</u>	<u>\$ (198,516)</u>	<u>\$ (361,255)</u>
<b>State Tax Calculation</b>					
18	CCR ARO Compliance Revenues	\$ 36,827	\$ 36,827	\$ 36,827	\$ 36,827
19	CCR ARO Compliance Recovery	(172,696)	(172,696)	(304,506)	(522,977)
20	Interest Expense	(2,768)	(4,109)	(5,742)	(7,595)
21	State Income Tax Deduction	7,538	7,611	14,867	26,847
22	Earnings Subject to State Tax	\$ (131,098)	\$ (132,366)	\$ (258,555)	\$ (466,898)
23	State Tax Rate	5.75%	5.75%	5.75%	5.75%
24	<b>State Income Tax</b>	<u>\$ (7,538)</u>	<u>\$ (7,611)</u>	<u>\$ (14,867)</u>	<u>\$ (26,847)</u>
<b>Federal Tax Calculation</b>					
25	CCR ARO Compliance Revenues	\$ 36,827	\$ 36,827	\$ 36,827	\$ 36,827
26	CCR ARO Compliance Recovery	(172,696)	(172,696)	(304,506)	(522,977)
27	Interest Expense	(2,768)	(4,109)	(5,742)	(7,595)
28	State Income Tax Deduction	7,538	7,611	14,867	26,847
29	Earnings Subject to Federal Tax	\$ (131,098)	\$ (132,366)	\$ (258,555)	\$ (466,898)
30	Federal Tax Rate	21.00%	21.00%	21.00%	21.00%
31	<b>Federal Income Tax</b>	<u>\$ (27,531)</u>	<u>\$ (27,797)</u>	<u>\$ (54,296)</u>	<u>\$ (98,049)</u>

Notes and Source:

Details may not add to totals due to rounding.

Cols. A-D: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 2 Traditional Base)

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Summary of Errata and Staff Adjustments For the Test Year

Test Year Ended July 31, 2020  
(Thousands of Dollars)

CONTAINS TRADE SECRET INFORMATION						
Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Staff Adjustment to Remove Contingency (D)	Staff Adjusted (E)
1	CCR ARO Compliance Regulatory Asset - Beginning Balance	\$ -	\$ -			
2	CCR ARO Compliance Expenditures	\$ 245,328	\$ (114)	\$ 245,214		
3	Amortization of Prior Under Recovery	\$ 80,340				
4	1/3 Recovery of 2020 Expenditures	\$ 92,356				
5	1/3 Recovery of 2021 Expenditures					
6	1/3 Recovery of 2022 Expenditures					
7	CCR ARO Compliance Recovery	<u>\$ 172,696</u>	<u>\$ (28)</u>	<u>\$ 172,668</u>		
8	CCR ARO Compliance Regulatory Asset - Ending Balance					\$ -
9	CCR ARO Compliance Regulatory Asset (13-Month average)	\$ 203,629	\$ 38	\$ 203,667	\$ (33,907)	\$ 169,760
10	Accumulated Deferred Income Taxes	<u>\$ (51,509)</u>	<u>\$ (10)</u>	<u>\$ (51,519)</u>	<u>\$ 8,577</u>	<u>\$ (42,942)</u>
11	CCR ARO Compliance Retail Rate Base	<u>\$ 152,120</u>	<u>\$ 29</u>	<u>\$ 152,149</u>	<u>\$ (25,330)</u>	<u>\$ 126,818</u>
<b>Operating Income Deficiency</b>						
12	CCR ARO Compliance Revenues Included in Current Rates	\$ 36,827	\$ -	\$ 36,827		\$ 36,827
13	CCR ARO Compliance Recovery	(172,696)	\$ 28	\$ (172,668)	\$ 38,558	\$ (134,110)
14	Carrying Costs/Interest					\$ (5,162)
15	Earnings Before Taxes	\$ (135,869)	\$ 28	\$ (135,841)	\$ 38,558	\$ (102,445)
16	Federal Income Taxes	\$ 27,531	\$ (5)	\$ 27,525	\$ (7,182)	\$ 20,344
17	State Income Taxes	<u>\$ 7,538</u>	<u>\$ (1)</u>	<u>\$ 7,537</u>	<u>\$ (1,966)</u>	<u>\$ 5,570</u>
18	<b>Operating Income Deficiency</b>	<u>\$ (100,800)</u>	<u>\$ 21</u>	<u>\$ (100,779)</u>	<u>\$ 29,410</u>	<u>\$ (76,531)</u>

Notes and Source

Details may not add to totals due to rounding.

Col. A: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 2 Traditional Base)

Col. B: Amounts from Company Errata Exhibit 1; also see page 10 of 10

Col. C: Col. A + Col. B

Cols. D-E: See page 9 of 10

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Summary of Errata and Staff Adjustments for Calendar 2020

Calendar 2020  
(Thousands of Dollars)

CONTAINS TRADE SECRET INFORMATION						
Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Staff Adjustment to Remove Contingency (D)	Staff Adjusted (E)
1	CCR ARO Compliance Regulatory Asset - Beginning Balance	\$ 241,020	\$ 60	\$ 241,080		
2	CCR ARO Compliance Expenditures	\$ 277,068	\$ (169)	\$ 276,899		
3	Amortization of Prior Under Recovery	\$ 80,340	\$ 20	\$ 80,360		
4	1/3 Recovery of 2020 Expenditures	\$ 92,356	\$ (56)	\$ 92,300		
5	1/3 Recovery of 2021 Expenditures					
6	1/3 Recovery of 2022 Expenditures					
7	CCR ARO Compliance Recovery	<u>\$ 172,696</u>	<u>\$ (36)</u>	<u>\$ 172,660</u>		
8	CCR ARO Compliance Regulatory Asset - Ending Balance	\$ 345,391	\$ (72)	\$ 345,319	\$ (77,104)	\$ 268,215
9	CCR ARO Compliance Regulatory Asset (13-Month average)	\$ 293,205	\$ (6)	\$ 293,199	\$ (60,937)	\$ 232,263
10	Accumulated Deferred Income Taxes	<u>\$ (74,168)</u>	<u>\$ 2</u>	<u>\$ (74,166)</u>	<u>\$ 15,414</u>	<u>\$ (58,752)</u>
11	CCR ARO Compliance Retail Rate Base	<u>\$ 219,038</u>	<u>\$ (5)</u>	<u>\$ 219,033</u>	<u>\$ (45,522)</u>	<u>\$ 173,511</u>
<b>Operating Income Deficiency</b>						
12	CCR ARO Compliance Revenues Included in Current Rates	\$ 36,827	\$ -	\$ 36,827		\$ 36,827
13	CCR ARO Compliance Recovery	(172,696)	\$ 36	\$ (172,660)	\$ 38,552	\$ (134,107)
14	Carrying Costs/Interest					\$ (7,201)
15	Earnings Before Taxes	\$ (135,869)	\$ 36	\$ (135,832)	\$ 38,552	\$ (104,481)
16	Federal Income Taxes	\$ 27,797	\$ (7)	\$ 27,790	\$ (7,042)	\$ 20,748
17	State Income Taxes	<u>\$ 7,611</u>	<u>\$ (2)</u>	<u>\$ 7,609</u>	<u>\$ (1,928)</u>	<u>\$ 5,681</u>
18	<b>Operating Income Deficiency</b>	<u>\$ (100,461)</u>	<u>\$ 27</u>	<u>\$ (100,434)</u>	<u>\$ 29,582</u>	<u>\$ (78,052)</u>

Notes and Source

Details may not add to totals due to rounding.

Col. A: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 2 Traditional Base

Col. B: Amounts from Company Errata Exhibit 1; also see page 10 of 10

Col. C: Col. A + Col. B

Cols. D-E: See page 9 of 10



Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Summary of Errata and Staff Adjustments for Calendar 2021

Calendar 2021  
(Thousands of Dollars)

CONTAINS TRADE SECRET INFORMATION						
Line No.	Description	Per Company As-Filed (A)	Per Company Errata Adjustments (B)	Company Adjusted (C)	Staff Adjustment to Remove Contingency (D)	Staff Adjusted (E)
1	CCR ARO Compliance Regulatory Asset - Beginning Balance	\$ 345,391	\$ (72)	\$ 345,319		
2	CCR ARO Compliance Expenditures	\$ 395,432	\$ (335)	\$ 395,097		
3	Amortization of Prior Under Recovery	\$ 80,340	\$ 20	\$ 80,360		
4	1/3 Recovery of 2020 Expenditures	\$ 92,356	\$ (56)	\$ 92,300		
5	1/3 Recovery of 2021 Expenditures	\$ 131,811	\$ (112)	\$ 131,699		
6	1/3 Recovery of 2022 Expenditures					
7	CCR ARO Compliance Recovery	<u>\$ 304,506</u>	<u>\$ (148)</u>	<u>\$ 304,359</u>		
8	CCR ARO Compliance Regulatory Asset - Ending Balance	\$ 436,317	\$ (260)	\$ 436,058	\$ (110,004)	\$ 326,053
9	CCR ARO Compliance Regulatory Asset (13-Month average)	\$ 390,854	\$ (166)	\$ 390,688	\$ (93,555)	\$ 297,134
10	Accumulated Deferred Income Taxes	<u>\$ (98,869)</u>	<u>\$ 42</u>	<u>\$ (98,827)</u>	<u>\$ 23,665</u>	<u>\$ (75,161)</u>
11	CCR ARO Compliance Retail Rate Base	<u>\$ 291,986</u>	<u>\$ (124)</u>	<u>\$ 291,862</u>	<u>\$ (69,890)</u>	<u>\$ 221,972</u>
<b>Operating Income Deficiency</b>						
12	CCR ARO Compliance Revenues Included in Current Rates	\$ 36,827	\$ -	\$ 36,827		\$ 36,827
13	CCR ARO Compliance Recovery	(304,506)	\$ 148	\$ (304,359)	\$ 74,279	\$ (230,080)
14	Carrying Costs/Interest					\$ (9,345)
15	Earnings Before Taxes	\$ (267,679)	\$ 148	\$ (267,531)	\$ 74,279	\$ (202,598)
16	Federal Income Taxes	\$ 54,296	\$ (30)	\$ 54,267	\$ (14,034)	\$ 40,232
17	State Income Taxes	<u>\$ 14,867</u>	<u>\$ (8)</u>	<u>\$ 14,859</u>	<u>\$ (3,843)</u>	<u>\$ 11,016</u>
18	<b>Operating Income Deficiency</b>	<u>\$ (198,516)</u>	<u>\$ 110</u>	<u>\$ (198,406)</u>	<u>\$ 56,401</u>	<u>\$ (151,350)</u>

Notes and Source

Details may not add to totals due to rounding.

Col. A: Amounts from Exhibit (DPP/SPA/MBR-1, Schedule 2 Traditional Base

Col. B: Amounts from Company Errata Exhibit 1; also see page 10 of 10

Col. C: Col. A + Col. B

Cols. D-E: See page 9 of 10

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Summary of Errata and Staff Adjustments Calendar 2022

Calendar 2022  
(Thousands of Dollars)

CONTAINS TRADE SECRET INFORMATION				Per	Staff	
Line		Per	Company	Company	Adjustment	Staff
No.	Description	Company	Errata	Adjusted	to Remove	Adjusted
		As-Filed	Adjustments	(C)	Contingency	(F)
		(A)	(B)		(D)	
1	CCR ARO Compliance Regulatory Asset - Beginning Balance	\$ 436,317	\$ (260)	\$ 436,058		
2	CCR ARO Compliance Expenditures	\$ 655,412	\$ (329)	\$ 655,083		
3	Amortization of Prior Under Recovery	\$ 80,340	\$ 20	\$ 80,360		
4	1/3 Recovery of 2020 Expenditures	\$ 92,356	\$ (56)	\$ 92,300		
5	1/3 Recovery of 2021 Expenditures	\$ 131,811	\$ (112)	\$ 131,699		
6	1/3 Recovery of 2022 Expenditures	\$ 218,471	\$ (110)	\$ 218,361		
7	CCR ARO Compliance Recovery	\$ 522,977	\$ (257)	\$ 522,720		
8	CCR ARO Compliance Regulatory Asset - Ending Balance	\$ 568,752	\$ (331)	\$ 568,421	\$ (158,826)	\$ 409,596
9	CCR ARO Compliance Regulatory Asset (13-Month average)	\$ 502,535	\$ (295)	\$ 502,239	\$ (134,415)	\$ 367,824
10	Accumulated Deferred Income Taxes	\$ (127,119)	\$ 75	\$ (127,044)	\$ 34,001	\$ (93,043)
11	CCR ARO Compliance Retail Rate Base	\$ 375,416	\$ (221)	\$ 375,195	\$ (100,414)	\$ 274,781
Operating Income Deficiency						
12	CCR ARO Compliance Revenues Included in Current Rates	\$ 36,827	\$ -	\$ 36,827		\$ 36,827
13	CCR ARO Compliance Recovery	\$ (522,977)	\$ 257	\$ (522,720)	\$ 135,828	\$ (386,892)
14	Carrying Costs/Interest					\$ (11,513)
15	Earnings Before Taxes	\$ (486,150)	\$ 257	\$ (485,893)	\$ 135,828	\$ (361,577)
16	Federal Income Taxes	\$ 98,049	\$ (52)	\$ 97,997	\$ (26,194)	\$ 71,803
17	State Income Taxes	\$ 26,847	\$ (14)	\$ 26,832	\$ (7,172)	\$ 19,660
18	Operating Income Deficiency	\$ (361,255)	\$ 191	\$ (361,063)	\$ 102,462	\$ (270,115)

Notes and Source

Details may not add to totals due to rounding.

Col. A: Amounts from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 2 Traditional Base

Col. B: Amounts from Company Errata Exhibit 1; also see page 10 of 10

Col. C: Col. A + Col. B

Cols. D-E: See page 9 of 10

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Impacts of the Company's Errata Adjustments With Contingencies Removed

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

**CONTAINS TRADE SECRET INFORMATION**

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
<b>Per Staff</b>					
1	CCR ARO Compliance Regulatory Asset - Beginning Balance				
2	CCR ARO Compliance Expenditures				
3	Amortization of Prior Under Recovery				
4	1/3 Recovery of 2020 Expenditures				
5	1/3 Recovery of 2021 Expenditures				
6	1/3 Recovery of 2022 Expenditures				
7	CCR ARO Compliance Recovery				
8	CCR ARO Compliance Regulatory Asset - Ending Balance				
9	CCR ARO Compliance Regulatory Asset (13-Month average)				
10	Accumulated Deferred Income Taxes				
11	CCR ARO Compliance Retail Rate Base	\$ 126,818	\$ 173,511	\$ 221,972	\$ 274,781
11a	Staff Recommended Rate Base	\$ -	\$ -	\$ -	\$ -
<b>Operating Income Deficiency</b>					
12	CCR ARO Compliance Revenues Included in Current Rates	\$ 36,827	\$ 36,827	\$ 36,827	\$ 36,827
13	CCR ARO Compliance Recovery	(134,110)	(134,107)	(230,080)	(386,892)
13a	Carrying Costs/Interest	(5,162)	(7,201)	(9,345)	(11,513)
14	Earnings Before Taxes	\$ (102,445)	\$ (104,481)	\$ (202,598)	\$ (361,577)
15	Federal Income Taxes	20,344	20,748	40,232	71,803
16	State Income Taxes	5,570	5,681	11,016	19,660
17	<b>Operating Income Deficiency</b>	<u>\$ (76,531)</u>	<u>\$ (78,052)</u>	<u>\$ (151,350)</u>	<u>\$ (270,115)</u>
<b>State Tax Calculation</b>					
18	CCR ARO Compliance Revenues	\$ 36,827	\$ 36,827	\$ 36,827	\$ 36,827
19	CCR ARO Compliance Recovery	(134,110)	(134,107)	(230,080)	(386,892)
20	Carrying Costs/Interest	(5,162)	(7,201)	(9,345)	(11,513)
21	State Income Tax Deduction	5,570	5,681	11,016	19,660
22	Earnings Subject to State Tax	\$ (96,875)	\$ (98,801)	\$ (191,582)	\$ (341,918)
23	State Tax Rate	5.75%	5.75%	5.75%	5.75%
24	<b>State Income Tax</b>	<u>\$ (5,570)</u>	<u>\$ (5,681)</u>	<u>\$ (11,016)</u>	<u>\$ (19,660)</u>
<b>Federal Tax Calculation</b>					
25	CCR ARO Compliance Revenues	\$ 36,827	\$ 36,827	\$ 36,827	\$ 36,827
26	CCR ARO Compliance Recovery	(134,110)	(134,107)	(230,080)	(386,892)
27	Carrying Costs/Interest	(5,162)	(7,201)	(9,345)	(11,513)
28	State Income Tax Deduction	5,570	5,681	11,016	19,660
29	Earnings Subject to Federal Tax	\$ (96,875)	\$ (98,800)	\$ (191,582)	\$ (341,917)
30	Federal Tax Rate	21.00%	21.00%	21.00%	21.00%
31	<b>Federal Income Tax</b>	<u>\$ (20,344)</u>	<u>\$ (20,748)</u>	<u>\$ (40,232)</u>	<u>\$ (71,803)</u>

Notes and Source

Details may not add to totals due to rounding.

Cols. A-D, lines 1-11: Amounts from Trade Secret Attachment STF-PIA-14-4

**Line 13a - Carrying Cost/Interest**

32	Rate Base/Balance for carrying costs (line 11)	\$ 126,818	\$ 173,511	\$ 221,972	\$ 274,781
33	Long-Term Cost of Debt (Exhibit (RS/RT-2), Schedule D)	4.07%	4.15%	4.21%	4.19%
34	Carrying Cost	<u>\$ 5,162</u>	<u>\$ 7,201</u>	<u>\$ 9,345</u>	<u>\$ 11,513</u>

Georgia Power Company  
Coal Combustion Residuals (CCR) - Asset Retirement Obligation (ARO) Compliance  
Company Errata Adjustments

For the 12 Months Ending July 31, 2020 and December 31, 2020-2022  
(Thousands of Dollars)

Line No.	Description	Test Period (A)	2020 (B)	2021 (C)	2022 (D)
1	<b>CCR ARO Compliance Regulatory Asset - Beginning Balance</b>	\$ -	\$ 60	\$ (72)	\$ (260)
2	<b>CCR ARO Compliance Expenditures</b>	\$ (114)	\$ (169)	\$ (335)	\$ (329)
3	Amortization of Prior Under Recovery		\$ 20	\$ 20	\$ 20
4	1/3 Recovery of 2020 Expenditures		(56)	(56)	(56)
5	1/3 Recovery of 2021 Expenditures		-	(112)	(112)
6	1/3 Recovery of 2022 Expenditures		-	-	(110)
7	<b>CCR ARO Compliance Recovery</b>	\$ (28)	\$ (36)	\$ (148)	\$ (257)
8	<b>CCR ARO Compliance Regulatory Asset - Ending Balance</b>		\$ (72)	\$ (260)	\$ (331)
9	CCR ARO Compliance Regulatory Asset (13-Month average)	\$ 38	\$ (6)	\$ (166)	\$ (295)
10	Accumulated Deferred Income Taxes	(10)	2	42	75
11	<b>CCR ARO Compliance Retail Rate Base</b>	<u>\$ 29</u>	<u>\$ (5)</u>	<u>\$ (124)</u>	<u>\$ (221)</u>
	<b>Operating Income Deficiency</b>				
12	CCR ARO Compliance Revenues Included in Current Rates	\$ -	\$ -	\$ -	\$ -
13	CCR ARO Compliance Recovery	28	36	148	257
14	Earnings Before Taxes	\$ 28	\$ 36	\$ 148	\$ 257
15	Federal Income Taxes	(5)	(7)	(30)	(52)
16	State Income Taxes	(1)	(2)	(8)	(14)
17	<b>Operating Income Deficiency</b>	<u>\$ 21</u>	<u>\$ 27</u>	<u>\$ 110</u>	<u>\$ 191</u>
18	CCR ARO Compliance Retail Rate Base	\$ 29	\$ (5)	\$ (124)	\$ (221)
19	Requested Rate of Return	× 7.93%	7.98%	8.07%	8.13% (a)
20	Earnings Requirement	\$ 2	\$ (0)	\$ (10)	\$ (18)
21	Less: Operating Income Deficiency	- 21	27	110	191
22	Earnings Deficiency	\$ (19)	\$ (27)	\$ (120)	\$ (209)
23	Income Expansion Factor	÷ 74.602%	74.596%	74.597%	74.598% (b)
24	CCR ARO Compliance Revenue Requirement	<u>\$ (25)</u>	<u>\$ (37)</u>	<u>\$ (161)</u>	<u>\$ (280)</u>
25	CCR ARO Compliance Incremental Increase		<u>\$ (37)</u>	<u>\$ (124)</u>	<u>\$ (120)</u>

Notes and Source

Details may not add to totals due to rounding.  
Cols. A-D: Amounts from Company Errata Exhibit 1

EXHIBIT\_\_(RS/RT-7)

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 1**

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**STF-L&A-1-65**

**Question:**

Plant Held For Future Use.

- a. Identify the amount of PHFFU by item as of 12/31/2017 and 12/31/2018.
- b. For each item of PHFFU, indicate whether it represents rights of way.
- c. For each item of PHFFU, indicate whether it represents land owned by the Company.
- d. For each item of PHFFU, identify and explain the intended use and when the item is anticipated to become utility plant in service.
- e. For each item of PHFFU, identify when the Company originally recorded the amount in the PHFFU account.
- f. Identify where each item of PHFFU is addressed in the Company's 2019 IRP. If an item of PHFFU is not addressed in the Company's 2019 IRP, explain why.

**Response:**

See STF-L&A-1-65 Attachment for items a-f. This attachment is being provided in electronic format only.

Plant Held for Future Use						
<u>Response to STF-L&amp;A-1-65, Parts a through f.</u>						
Description	a	a	b	c	d	e
	Balance As of Dec-2017	Balance As of Dec-2018	Right-of-Way / Easement ?	Land Owned by GPC?	Year of Anticipated Use in Providing Electric Service	Originally Recorded to PHFFU Account
Dawson Crossing - South Dahlonega 500kV Transmission Line Site	\$10,977,832	\$10,977,832	Yes	Yes	>2040	12/1/2008
Dawson Crossing - South Dahlonega 230kV Transmission Line Site	\$6,702,908	\$6,702,908	Yes	Yes	>2040	12/1/2008
Coal Mountain 230kV Transmission Line Site	\$1,315,440	\$1,315,440	No	Yes	2021	12/1/2008
Coal Mountain Substation Site	\$2,012,631	\$2,012,631	No	Yes	2021	12/1/2006
Northwinds Substation Site	\$9,951,216	\$0	No	Yes	2019	6/30/2009
Carpenter Flat Substation Site	\$2,264,978	\$2,264,978	No	Yes	2021	6/30/2009
New Hampstead Substation Site	\$53,836	\$53,836	No	Yes	>2040	6/30/2009
South Dahlonega - Clermont Jet 500kv Transmission Line Site	\$28,188,653	\$28,188,653	Yes	Yes	>2040	9/30/2009
South Dahlonega - Clermont Jet 230kv Transmission Line Site	\$17,268,413	\$17,268,413	Yes	Yes	>2040	9/30/2009
Bethabara-E. Walton 230kv Transmission Line Site	\$3,708,308	\$3,708,308	Yes	Yes	>2040	3/31/2011
Northwinds 230kv loop Transmission Line Site	\$194,718	\$0	Yes	Yes	2019	3/31/2011
Piedmont Substation Site	\$12,933,362	\$12,933,362	No	Yes	>2040	3/31/2011
Boyd Ave Substation Site	\$1,334,192	\$1,334,192	No	Yes	>2040	8/31/2012
St. Joe Timber Land / Stewart County	\$23,627,317	\$23,491,940	No	Yes	>2030	9/1/2012
McDonough - East Point 230 KV	\$89,188	\$89,188	Yes	Yes	>2040	Main Document, Attachment G
Uttoy Springs Substation Site	\$594,185	\$594,185	No	Yes	>2040	See Note (B)
Wallace Dam - Klondike 500 KV	\$3,628,989	\$3,628,989	Yes	Yes	>2040	See Note (B)
South Hall - Winder Transmission Line Site	\$883,035	\$883,035	Yes	Yes	>2031	See Note (A)
Medical Arts Center Substation Site	\$1,234,614	\$1,236,066	No	Yes	>2035	See Note (A)
Savannah Portside International- Old River Road Substation Site	\$0	\$30,266	No	Yes	>2023	Vol 3 [F]
<b>Total</b>	<b>\$126,963,815</b>	<b>\$116,714,221</b>			>2040	See Note (B)

Note (A) Items were not addressed in the Company's 2019 IRP because plant held falls outside the 10-year Transmission planning horizon.

Note (B) Items were not addressed in the Company's 2019 IRP because plant held falls outside the 5-year Area planning horizon.

Note (C) Item was not addressed in the Company's 2019 IRP because plant held is under construction and transferred to Plant in Service.

Note (D) Items were not addressed in the Company's 2019 IRP because the need dates were recently moved within the 5-year Area planning horizon.

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 5**

**STF- L&A-5-15**

**Question:**

For each of the following items of Plant Held for Future Use please provide the requested information:

Description	date_originally	date_expected	Balance
Land and Rights:			
Dawson Crossing-S Dahlonega 500KV Transmission Line	12/01/2008	2030	\$10,977,832
Dawson Crossing-S Dahlonega 230KV Transmission Line	12/01/2008	2030	\$6,702,908
Coal Mountain 230KV Transmission Line	12/01/2008	2030	\$1,315,440
Coal Mountain Substation Site	12/01/2006	2030	\$2,012,631
Northwinds Substation Site	06/30/2009	2019	\$9,951,216
Stewart County	09/01/2012	2030	\$23,627,317
Carpenter Flat Substation Site	06/30/2009	2030	\$2,264,978
New Hampstead Substation Site	06/30/2009	2030	\$53,836
S Dahlonega-Clermont Junct. 500KV Transmission Line	09/30/2009	2030	\$28,188,653
S Dahlonega-Clermont Junct. 230KV Transmission Line	09/30/2009	2030	\$17,268,413
Piedmont Substation Site	03/31/2011	2030	\$12,933,362
Bethabara-E. Walton 230KV Transmission Line	03/31/2011	2031	\$3,708,308
Northwinds 230KV Loop Transmission Line Site	03/31/2011	2018	\$194,718
Boyd Avenue Substation Site	08/31/2012	2030	\$1,334,192
McDonough - East Point DC 230KV	09/01/2014	2030	\$89,188
Utoy Springs	09/01/2014	2020	\$594,185
Wallace Dam - Klondike 500KV	09/01/2014	2031	\$3,628,989
South Hall - Winder	09/01/2014	2035	\$883,035
Medical Arts Substation Land	02/01/2017	2021	\$1,234,614

- a) Identify each listed location for which the Company has no written plan for use.
- b) For each location for which the Company does have a written plan for use, identify and provide a copy of the Company's written use plan and indicate when it was last updated.
- c) Indicate whether the item was addressed in the Company's 2016 IRP and if so where it is addressed.
- d) Indicate whether the item is addressed in the Company's 2019 IRP and if so where it is addressed.
- e) Indicate whether the property has been evaluated in 2018 or 2019 for being transferred to non-utility property.
- f) If an evaluation for whether each property with a projected use date of 2030 or beyond is still needed and/or should be transferred to non-utility property has not been conducted, explain why not.
- g) If an evaluation for whether each property with a projected use date of 2030 or beyond is still needed and/or should be transferred to non-utility property has been conducted, please identify and provide it.



**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 5**

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**Response:**

- a) All locations within Plant Held for Future Use (PHFFU) have a written plan for use.
- b) Please see STF-L&A-5-15 Attachment A for the written plan for each property classified as Plant Held for Future Use. The Company has quarterly meetings (last held on December 13, 2018) to discuss Transmission Planning, Area Planning, and Generation's analysis of future needs related to PHFFU. The quarterly meetings evaluate each property to determine if the property should remain classified in the PHFFU account, or if the property needs to be transferred to another account, including Non-Utility property. This attachment is being provided in electronic format only.
- c) Please see STF-L&A-5-15 Attachment B. This attachment is being provided in electronic format only.
- d) Please see the Company's response to STF-L&A-1-65 Attachment.
- e) Please see the response to part 'b'.
- f) Please see the response to part 'b'.
- g) Please see the response to part 'b'.

**Plant Held For Future Use**

<b><u>PHFFU Item</u></b>	<b><u>Project Description/Plan</u></b>
Dawson Crossing - South Dahlonega 500kV Transmission Line Site	Install 34 mile McGrau Ford Middle Fork 500 kV Transmission Line.
Dawson Crossing - South Dahlonega 230kV Transmission Line Site	Install 13 mile Dawson Crossing Palmer Creek 230 kV line. 3.3 miles was used in 2008 for the Dawson Crossing Palmer Creek 230 kV line. There is a plan to use remaining 10 miles in 2030 for the Palmer Creek South Dahlonega 230 kV line.
Coal Mountain 230kV Transmission Line Site	Line to the new Coal Mountain Substation site.
Coal Mountain Substation Site	Purchase land suitable for a distribution substation adjacent to the planned Cumming-McGrau Ford 230kV Line. Area transformer loading at Cumming, Matt and Hammonds Crossing substations will necessitate a new substation in the area north of the City of Cumming.
Northwinds Substation Site	Construct new 230/25 kV substation in Alpharetta Area. This project resolves three bank loading contingencies at Old Alabama Rd and Kimball Bridge Rd substations in 2019 and 2020. This project also resolves three normal feeder loading issues and one contingency feeder loading issue at Old Alabama Rd and Kimball Bridge Rd in 2019 and 2020.
Carpenter Flat Substation Site	Construct the new Carpenter Flat 230/25kV substation. This new substation will serve the Waleska area and off load Canton #2 substation.
New Hampstead Substation Site	Construct a new 230/25 kV distribution substation to serve the New Hampstead development in Savannah.
South Dahlonega - Clermont Jct 500kv Transmission Line Site	Install 34 mile McGrau Ford Middle Fork 500 kV Transmission Line.
South Dahlonega - Clermont Jct 230kv Transmission Line Site	Install 18 mile South Dahlonega Clermont Junction 230 kV Line adjacent to adjacent to the McGrau Ford Middle Fork 500 kV line
Bethabara-E. Walton 230kv Transmission Line Site	Install 13.3 mile Bethabara - E. Walton 230kv Line
Northwinds 230kv loop Transmission Line Site	Line to the new Northwinds Substation site.
Piedmont Substation Site	This project is to construct a future substation in the Buckhead area to accommodate future load growth in the area.
Boyd Ave Substation Site	Due to the continued growth in the Metro Area there is a need to add capacity to the present system. Specifically the Huff Road area of Atlanta. Build a two bank substation with space for a future third.
Stewart County	The Company is considering all options for the Stewart County site but at this time continues to expect the site to be developed into a future source of generation.
McDonough - East Point 230 KV	Line to new Utoy Springs Substation site.
Utoy Springs Substation Site	Construct a new 230/20-kV distribution substation. Construction of this substation will reduce loading on Cascade, Ben Hill and Camp Creek feeders and their banks and will improve reliability to the emerging Cascade Road I-285 intersection. The area surrounding the intersection of I-285 and Cascade Road is seeing significant development occur as there is significant parcels of land that have not been developed. This area is enhanced by its relatively close location to the downtown Atlanta area. Eventually the new load will cause one or several feeders to reach their guideline limits. Also, this area has experienced some reliability problems as it is somewhat distant from any of the substations that can serve it. Construction of a new substation in the area will give relief to distribution feeders, offload adjacent substation transformer banks and improve reliability to this emerging load center.
Wallace Dam - Klondike 500 KV	Install 63 mile South Hall - Wallace Dam, Wallace Dam - Klondike 500 KV, and Rockville East Walton 500 kV lines.
South Hall - Winder Transmission Line Site	Install 16 mile East Walton South Hall 500 kV line
Medical Arts Center Substation Site	This project acquires a sub site in the East/Central area of Savannah to facilitate the retirement of the Cornel Avenue 46kV substation and completes the South Chatham 46kV Retirement Project.

### Plant Held for Future Use

<b>Description</b>	<b>2016 IRP</b>
Dawson Crossing - South Dahlonega 500kV Transmission Line Site	See Note (A)
Dawson Crossing - South Dahlonega 230kV Transmission Line Site	See Note (A)
Coal Mountain 230kV Transmission Line Site	See Note (A)
Coal Mountain Substation Site	See Note (A)
Carpenter Flat Substation Site	See Note (A)
New Hampstead Substation Site	See Note (A)
South Dahlonega - Clermont Junction 500 kv Transmission Line Site	See Note (A)
South Dahlonega - Clermont Jct 230 kv Transmission Line Site	See Note (A)
Bethabara - East Walton 230kv Transmission Line Site	See Note (A)
Boyd Ave Substation Site	See Note (A)
Stewart County	See Note (A)
Wallace Dam - Klondike 500 KV	See Note (A)
South Hall - Winder Transmission Line Site	See Note (A)
McDonough - East Point 230 KV	See Note (B)
Utoy Springs Substation Site	See Note (B)
Medical Arts Center Substation Site	See Note (B)
Northwinds Substation Site	Volume 3 Section C3 (p 20)
Northwinds 230kv loop Transmission Line Site	Volume 3 Section C3 (p 20)
Piedmont Substation Site	Volume 3 Section C3 (p 21)

Note (A): Items were not addressed in the Company's 2016 IRP because they fell outside of the 10-year transmission planning horizon.

Note (B): These items were inadvertently omitted from the Company's 2016 IRP. However, it was provided in the Company's response to DR STF-2-25 in the 2016 IRP.

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 5**

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**STF-L&A-5-16**

**Question:**

Identify the related costs including maintenance, property taxes, financing costs etc incurred in 2018, and expected to be incurred in each year, 2019 through 2022, by amount and account.

**Response:**

The maintenance costs for Plant Held for Future Use (PHFFU) properties for 2018 and projected for 2019 through 2022 are for vegetation management. These costs are recorded to FERC account 571 Maintenance of Overhead Lines and actual expenses incurred in 2018 and budgeted expenses for 2019 through 2022 are as follows:

<b>Description</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>
Dawson Crossing-S Dahlenega 500kv T/L	-	-	-	-	-
Dawson Crossing-S Dahlenega 230kv T/L	-	-	-	-	-
Coal Mountain 230kv T/L	-	-	-	-	-
Coal Mountain Substation Site	-	-	-	-	-
Carpenter Flat Substation	-	-	-	-	-
New Hampstead Substation	-	-	-	-	-
S Dahlenega-Clermont Jct 500kv T/L	-	-	-	-	-
S Dahlenega-Clermont Jct 230kv T/L	-	-	-	-	-
Bethabara-E. Walton 230kv T/L Site	-	\$ 11,770	-	\$ 5,885	-
Piedmont Substation Site	-	-	-	-	-
Boyd Ave Substation Site	\$ 230	\$ 330	\$ 330	\$ 330	\$ 330
St. Joe Timber Land / Stewart County	-	-	-	-	-
McDonough-East Point DC 230 KV	-	-	-	-	-
Utoy Springs	-	-	-	-	-
Wallace Dam - Klondike 500 KV	\$ 104,797	-	\$ 91,560	-	\$ 45,780
South Hall - Winder T/L	-	-	-	-	-
Medical Arts Substation Land	\$ 532	\$ 532	\$ 532	\$ 532	\$ 532
Savannah Portside International- Old River Road	-	-	-	-	-

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 5**

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Please see the Company's response to STF-L&A-1-67 for the 2018 property tax expenses for PHFFU properties. Property tax expenses are recorded to FERC 408.1 Taxes Other Than Income Taxes. The budgeted property taxes for 2019 through 2022 are as follows:

Description	2019	2020	2021	2022
Dawson Crossing-S Dahlonga 500KV T/L	\$ 86,340	\$ 90,660	\$ 95,190	\$ 99,950
Dawson Crossing-S Dahlonga 230KV T/L	\$ 52,580	\$ 55,210	\$ 57,970	\$ 60,870
Coal Mountain 230 KV T/L	\$ 11,270	\$ 11,830	\$ 12,420	\$ 13,040
Coal Mountain Substation Site	\$ 17,830	\$ 18,720	\$ 19,660	\$ 20,640
Carpenter Flat Substation	\$ 26,420	\$ 27,740	\$ 29,130	\$ 30,590
New Hampstead Substation	\$ 620	\$ 650	\$ 680	\$ 710
S Dahlonga-Clermont Jct 500KV T/L	\$ 232,760	\$ 244,400	\$256,620	\$269,450
S Dahlonga-Clermont Jct 230KV T/L	\$ 142,000	\$ 149,100	\$156,560	\$164,390
Bethabara-E. Walton 230KV T/L Site	\$ 26,600	\$ 27,930	\$ 29,330	\$ 30,800
Piedmont Substation Site	\$ 159,970	\$ 167,970	\$176,370	\$185,190
Boyd Ave Substation Site	\$ 15,540	\$ 16,320	\$ 17,140	\$ 18,000
St. Joe Timber Land / Stewart County	\$ 263,970	\$ 277,170	\$291,030	\$305,580
McDonough-East Point 230 KV	\$ 640	\$ 670	\$ 700	\$ 740
Utoy Springs	\$ 10,000	\$ 10,500	\$ 11,030	\$ 11,580
Wallace Dam - Klondike 500 KV	\$ 21,610	\$ 22,690	\$ 23,820	\$ 25,010
South Hall - Winder T/L	\$ 6,330	\$ 6,650	\$ 6,980	\$ 7,330
Medical Arts Substation Land	\$ 20,820	\$ 21,860	\$ 22,950	\$ 24,100
Savannah Portside International - Old River Road	\$ 300	\$ 320	\$ 340	\$ 360

The financing costs are calculated on a total retail cost of service basis and are not tracked by individual PHFFU properties.

EXHIBIT\_\_(RS/RT-8)

THIS FILING IS	
Item 1: <input checked="" type="checkbox"/> An Initial (Original) Submission	OR <input type="checkbox"/> Resubmission No. ____

Form 1 Approved  
OMB No.1902-0021  
(Expires 12/31/2019)

Form 1-F Approved  
OMB No.1902-0029  
(Expires 12/31/2019)

Form 3-Q Approved  
OMB No.1902-0205  
(Expires 12/31/2019)



# FERC FINANCIAL REPORT

## FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

<b>Exact Legal Name of Respondent (Company)</b> Georgia Power Company	<b>Year/Period of Report</b> End of <u>2018/Q4</u>
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Name of Respondent Georgia Power Company		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4
ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)					
1. Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.					
2. For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.					
Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)	
1	Land and Rights:				
2	Dawson Crossing-S Dahlenega 500KV Transmission Line	12/01/2008	2040	10,977,832	
3	Dawson Crossing-S Dahlenega 230KV Transmission Line	12/01/2008	2040	6,702,908	
4	Coal Mountain 230KV Transmission Line	12/01/2008	2021	1,315,440	
5	Coal Mountain Substation Site	12/01/2006	2021	2,012,631	
6	Stewart County	09/01/2012	2030	23,491,940	
7	Carpenter Flat Substation Site	06/30/2009	2021	2,264,978	
8	New Hampstead Substation Site	06/30/2009	2040	53,836	
9	S Dahlenega-Clermont Junct. 500KV Transmission Line	09/30/2009	2040	28,188,653	
10	S Dahlenega-Clermont Junct. 230KV Transmission Line	09/30/2009	2040	17,268,413	
11	Piedmont Substation Site	03/31/2011	2040	12,933,362	
12	Bethabara-E. Walton 230KV Transmission Line	03/31/2011	2040	3,708,308	
13	Boyd Avenue Substation Site	08/31/2012	2040	1,334,192	
14	McDonough - East Point DC 230KV	09/01/2014	2040	89,188	
15	Utoy Springs	09/01/2014	2040	594,185	
16	Wallace Dam - Klondike 500KV	09/01/2014	2031	3,628,989	
17	South Hall - Winder	09/01/2014	2035	883,035	
18	Medical Arts Substation Land	02/01/2017	2023	1,236,065	
19	Savannah Portside Int.-Old River Rd. Substation Site	02/01/2017	2040	30,266	
20					
21	Other Property:				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	Total			116,714,221	



EXHIBIT\_\_(RS/RT-9)

Line No.	Description and Location of Property	Date Originally Included in This Account (A)	Date Expected to be used in Utility Service (B)	Balance at End of Year (C)	PHFFU with a Projected "Use" Date of 2030 or Beyond (D)	PHFFU with a Projected "Use" Date of 2040 or Beyond (E)
1	Land and Rights:					
2	Dawson Crossing-S Dahlonga 500KV Transmission Line	12/1/2008	2040	\$ 10,977,832	\$ 10,977,832	\$ 10,977,832
3	Dawson Crossing-S Dahlonga 230KV Transmission Line	12/1/2008	2040	\$ 6,702,908	\$ 6,702,908	\$ 6,702,908
4	Coal Mountain 230KV Transmission Line	12/1/2008	2021	\$ 1,315,440		
5	Coal Mountain Substation Site	12/1/2006	2021	\$ 2,012,631		
6	Stewart County	9/1/2012	2030	\$ 23,490,940	\$ 23,490,940	
7	Carpenter Flat Substation Site	6/30/2009	2021	\$ 2,264,978		
8	New Hampstead Substation Site	6/30/2009	2040	\$ 53,836	\$ 53,836	\$ 53,836
9	S Dahlonga-Clermont Junct. 500KV Transmission Line	9/30/2009	2040	\$ 28,188,653	\$ 28,188,653	\$ 28,188,653
10	S Dahlonga-Clermont Junct. 230KV Transmission Line	9/30/2009	2040	\$ 17,268,413	\$ 17,268,413	\$ 17,268,413
11	Piedmont Substation Site	3/31/2011	2040	\$ 12,933,362	\$ 12,933,362	\$ 12,933,362
12	Bethabara-E. Walton 230KV Transmission Line	3/31/2011	2040	\$ 3,708,308	\$ 3,708,308	\$ 3,708,308
13	Boyd Avenue Substation Site	8/31/2012	2040	\$ 1,334,192	\$ 1,334,192	\$ 1,334,192
14	McDonough - East Point DC 230KV	9/1/2014	2040	\$ 89,188	\$ 89,188	\$ 89,188
15	Utoy Springs	9/1/2014	2040	\$ 594,185	\$ 594,185	\$ 594,185
16	Wallace Dam - Klondike 500KV	9/1/2014	2031	\$ 3,628,989	\$ 3,628,989	
17	South Hall - Winder	9/1/2014	2035	\$ 883,035	\$ 883,035	
18	Medical Arts Substation Land	2/1/2017	2023	\$ 1,234,614		
19	Savannah Portside Int-Old River Rd. Substation Site	2/1/2017	2040	\$ 30,266	\$ 30,266	\$ 30,266
20	Other Property:					
21	TOTAL			<u>\$ 116,711,770</u>		
22	Cost of Future Use Property with Projected "Use" Date of 2030 or Beyond (Col.D) and 2040 or beyond (Col.E)				<u>\$ 109,884,107</u>	<u>\$ 81,881,143</u>
23	Percentage of total December 31, 2018 PHFFU Cost with Projected "Use" Dates of 2030 and 2040 or Beyond				<u>94.1%</u>	<u>70.2%</u>

Notes and Source  
2018 FERC Form 1, page 214

EXHIBIT\_\_(RS/RT-10)

Line No.	Component of Cost	Amount at a 9.2% ROE with Staff Proposed Capital Structure (A)	Amount at a 10% ROE (B)	Amount at a 12% ROE (C)	Reference
1	Maintenance - 2020 estimated	\$ 92,422	\$ 92,422	\$ 92,422	Page 2
2	Property Taxes - 2020 estimated	\$ 1,150,390	\$1,150,390	\$1,150,390	Page 3
3	Financing Cost @ 9.20% ROE/ 6.69% ROR	\$ 9,676,000			Page 4
4	Financing Cost @ 10% ROE		\$10,704,000	\$10,704,000	Page 4
5	Additional Financing Cost to 12% ROE			\$1,722,000	Page 4
6	Estimated Annual Cost to Customers	<u>\$ 10,918,812</u>	<u>\$ 11,946,812</u>	<u>\$ 13,668,812</u>	
6	Approximate Annual Cost in millions	<u>\$ 10.9</u>	<u>\$ 11.9</u>	<u>\$ 13.7</u>	

The maintenance costs for Plant Held for Future Use (PHFFU) properties for 2018 and projected for 2019 through 2022 are for vegetation management. These costs are recorded to FERC account 571 Maintenance of Overhead Lines and actual expenses incurred in 2018 and budgeted expenses for 2019 through 2022 are as follows:

Description	2018	2019	2020	2021	2022
Dawson Crossing-S Dahlonega 500kv T/L	-	-	-	-	-
Dawson Crossing-S Dahlonega 230kv T/L	-	-	-	-	-
Coal Mountain 230kv T/L	-	-	-	-	-
Coal Mountain Substation Site	-	-	-	-	-
Carpenter Flat Substation	-	-	-	-	-
New Hampstead Substation	-	-	-	-	-
S Dahlonega-Clermont Jct 500kv T/L	-	-	-	-	-
S Dahlonega-Clermont Jct 230kv T/L	-	-	-	-	-
Bethabara-E. Walton 230kv T/L Site	-	\$11,770	-	\$5,885	-
Piedmont Substation Site	-	-	-	-	-
Boyd Ave Substation Site	\$230	\$330	\$330	\$330	\$330
St. Joe Timber Land / Stewart County	-	-	-	-	-
McDonough-East Point DC 230 KV	-	-	-	-	-
Utoy Springs	-	-	-	-	-
Wallace Dam - Klondike 500 KV	\$104,797	-	\$91,560	-	\$45,780
South Hall - Winder T/L	-	-	-	-	-
Medical Arts Substation Land	\$532	\$532	\$532	\$532	\$532
Savannah Portside International- Old River Road	-	-	-	-	-
Totals	\$ 105,559	\$ 12,632	\$ 92,422	\$ 6,747	\$ 46,642

Source:

Company's response to STF-L&A-5-16 in Docket No. 42310, with totals added

PHFFU budgeted property taxes

Description	2019	2020	2021	2022
Dawson Crossing-S Dahlonega 500KV T/L	\$86,340	\$90,660	\$95,190	\$99,950
Dawson Crossing-S Dahlonega 230KV T/L	\$52,580	\$55,210	\$57,970	\$60,870
Coal Mountain 230 KV T/L	\$11,270	\$11,830	\$12,420	\$13,040
Coal Mountain Substation Site	\$17,830	\$18,720	\$19,660	\$20,640
Carpenter Flat Substation	\$26,420	\$27,740	\$29,130	\$30,590
New Hampstead Substation	\$620	\$650	\$680	\$710
S Dahlonega-Clermont Jct 500KV T/L	\$232,760	\$244,400	\$256,620	\$269,450
S Dahlonega-Clermont Jct 230KV T/L	\$142,000	\$149,100	\$156,560	\$164,390
Bethabara-E. Walton 230KV T/L Site	\$26,600	\$27,930	\$29,330	\$30,800
Piedmont Substation Site	\$159,970	\$167,970	\$176,370	\$185,190
Boyd Ave Substation Site	\$15,540	\$16,320	\$17,140	\$18,000
St. Joe Timber Land / Stewart County	\$263,970	\$277,170	\$291,030	\$305,580
McDonough-East Point 230 KV	\$640	\$670	\$700	\$740
Utoy Springs	\$10,000	\$10,500	\$11,030	\$11,580
Wallace Dam - Klondike 500 KV	\$21,610	\$22,690	\$23,820	\$25,010
South Hall - Winder T/L	\$6,330	\$6,650	\$6,980	\$7,330
Medical Arts Substation Land	\$20,820	\$21,860	\$22,950	\$24,100
Savannah Portside International - Old River Road	\$300	\$320	\$340	\$360
Totals	\$1,095,600	\$1,150,390	\$1,207,920	\$1,268,330

Source:

Company's response to STF-L&A-5-16 in Docket No. 42310, with totals added

Line No.	Description	Using Staff	Based on Current Sharing Range		Source
		Proposed 2020 Cost of Capital	Top of Range Amount	Bottom of Range Amount	
		(A)	(B)	(C)	
1	Plant Held for Future Use - December 31, 2018	\$ 116,714,221	\$ 116,714,221	\$ 116,714,221	FERC Form
2	Pre-Tax Cost of Capital	8.29%	10.65%	9.17%	See below
3	Estimated Annual Financing Cost 2018	\$ 9,676,000	\$ 12,426,000	\$ 10,704,000	
		To page 1		To page 1	
4	Increment from 10% to 12% ROE		\$ 1,722,000		
			To page 1		

Capital Structure and Cost Rates - Col.A, Line 2

	Component	Proportion	Cost	Weighted Cost	Tax Expansion Factor	Weighted Cost of Capital Pre-Tax
5	Long-Term Debt	49.00%	4.07%	1.99%		1.99%
6	Common Equity	51.00%	9.20%	4.69%	0.74528	6.30%
7	Total	100.00%		6.69%		8.29%

Exhibit \_\_ (RS/RT-2), Schedule D

Capital Structure and Cost Rates - Col.B, Line 2

	Component	Proportion	Cost	Weighted Cost	Tax Expansion Factor	Weighted Cost of Capital Pre-Tax
8	Long-Term Debt	45.00%	3.98%	1.79%		1.79%
9	Common Equity	55.00%	12.00%	6.60%	0.74528	8.86%
10	Total	100.00%		8.39%		10.65%

Source; 2018 ASR Section 1, pages 1 and 2 of 6

Capital Structure and Cost Rates - Col.C, Line 2

	Component	Proportion	Cost	Weighted Cost	Tax Expansion Factor	Weighted Cost of Capital Pre-Tax
11	Long-Term Debt	45.00%	3.98%	1.79%		1.79%
12	Common Equity	55.00%	10.00%	5.50%	0.74528	7.38%
13	Total	100.00%		7.29%		9.17%

Source; 2018 ASR Section 1, pages 1 and 2 of 6; with 10% ROE for bottom of earnings sharing range.

EXHIBIT\_\_(RS/RT-11)



**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NOS. 42310 & 42311**

**Data Request No. STF-L&A-1-23**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS A TRADE SECRET**

As part of Georgia Power Company's 2019 Integrated Resource Plan filed in Docket No. 42310 ("2019 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 42311 ("2019 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-L&A-1-23 ("Response"). In the Response, the Company has provided detailed financial information regarding the estimated future expenditures for ash pond closures. All of such information (the "Information") constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details on the costs the Company is expected to incur to close its ash ponds. Publicly disclosing these costs would allow vendors to tailor proposals according to the Company's expected costs to the detriment of the Company and its customers. Disclosure of the Information could harm the Company in its efforts to obtain optimal pricing in current or future negotiations.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 1**

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**STF-L&A-1-23**

**Question:**

Please reference the Coal Combustion Residuals Asset Retirement Obligations ("TS 2019 IRP CCR ARO") found in the Selected Supporting Information section of Technical Appendix Volume 1.

- a. Please provide a breakdown of each numerical value in the table by generating unit.
- b. Please provide all supporting documents/workpapers that were used to compute the values in the table. Workpapers should be supplied electronically with all formulas attached and no pasted in data assumptions should exist.

**Response:**

- a. See STF-L&A-1-23 Attachment A for a breakdown of each numerical value in the table by plant. CCR AROs are considered common plant assets as they are shared by generating units at the same site. This attachment is being provided in electronic format only.
- b. See STF-L&A-1-23 Attachment B. Due to the voluminous nature of the data, the attachment is being provided in electronic format only and has been redacted in its entirety for public disclosure purposes.

**Ash Ponds**

Facility	Project to Date 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029 & Beyond	Total
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McDonough	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McManus	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Mitchell	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ash Pond Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

**Landfills**

Facility	Project to Date 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029 & Beyond	Total
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Landfill Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total	\$ 406.5	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	\$ 7,585.0

PD STF-L&A-1-23 Attachment B.xlsx

**PUBLIC DISCLOSURE**

Data redacted in its entirety.

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NOS. 42310 & 42311**

**Data Request No. STF-L&A-1-25**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS A TRADE SECRET**

As part of Georgia Power Company's 2019 Integrated Resource Plan filed in Docket No. 42310 ("2019 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 42311 ("2019 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-L&A-1-25 ("Response"). In the Response, the Company has provided detailed financial information regarding the estimated future expenditures for ash pond closures. All of such information (the "Information") constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details on the costs the Company is expected to incur to close its ash ponds. Publicly disclosing these costs would allow vendors to tailor proposals according to the Company's expected costs to the detriment of the Company and its customers. Disclosure of the Information could harm the Company in its efforts to obtain optimal pricing in current or future negotiations.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 1**

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**STF-L&A-1-25**

**Question:**

Provide a breakdown of the CCR ARO for the years "2029 & Beyond" by generating unit.

**Response:**

See TS STF-L&A-1-25 Attachment for a breakdown of each numerical value in the table by plant. CCR AROs are considered common plant assets as they are shared by generating units at the same site. The attachment is being provided in electronic format only.

Ash Ponds Facility	(\$ in millions)											
	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McDonough	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McManus	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Mitchell	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ash Pond Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Landfills Facility	(\$ in millions)											
	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Landfill Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Total	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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Note: Plant Gaston is owned by Southern Electric Generating Company ("SESCO"), an indirect public utility subsidiary of Southern Company. The Company owns 50% of the outstanding common stock of SESCO and Alabama Power Company ("Alabama Power"), a wholly owned public utility subsidiary of Southern, owns the remaining outstanding common stock. Ash pond closure costs and liabilities are recorded on SESCO's books.

**Ash Ponds**

Facility	<u>2041</u>	<u>2042</u>	<u>2043</u>	<u>2044</u>	<u>2045</u>	<u>2046</u>	<u>2047</u>	<u>2048</u>	<u>2049</u>	<u>2050</u>	<u>2051</u>	<u>2052</u>
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McDonough	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McManus	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Mitchell	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ash Pond Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

**Landfills**

Facility	<u>2041</u>	<u>2042</u>	<u>2043</u>	<u>2044</u>	<u>2045</u>	<u>2046</u>	<u>2047</u>	<u>2048</u>	<u>2049</u>	<u>2050</u>	<u>2051</u>	<u>2052</u>
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Landfill Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED



**Ash Ponds**

Facility	<u>2053</u>	<u>2054</u>	<u>2055</u>	<u>2056</u>	<u>2057</u>	<u>2058</u>	<u>2059</u>	<u>2060</u>	<u>2061</u>	<u>2062</u>	<u>2063</u>	<u>2064</u>
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McDonough	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McManus	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Mitchell	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ash Pond Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

**Landfills**

Facility	<u>2053</u>	<u>2054</u>	<u>2055</u>	<u>2056</u>	<u>2057</u>	<u>2058</u>	<u>2059</u>	<u>2060</u>	<u>2061</u>	<u>2062</u>	<u>2063</u>	<u>2064</u>
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Landfill Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

**Ash Ponds**

Facility	<u>2065</u>	<u>2066</u>	<u>2067</u>	<u>Total</u>
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED
McDonough	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED
McManus	REDACTED	REDACTED	REDACTED	REDACTED
Mitchell	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED
Ash Pond Subtotal	REDACTED	REDACTED	REDACTED	REDACTED

**Landfills**

Facility	<u>2065</u>	<u>2066</u>	<u>2067</u>	<u>2068</u>	<u>2069</u>	<u>2070</u>	<u>2071</u>	<u>2072</u>	<u>2073</u>	<u>2074</u>	<u>2075</u>	<u>Total</u>
Arkwright	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Landfill Subtotal	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

**Total**

REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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EXHIBIT\_\_(RS/RT-12)

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 1**

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**STF-L&A-1-13**

**Question:**

At which company-owned coal-fired power plant will the center for beneficial use of harvested CCR be located?

**Response:**

This center will be built and operated by EPRI at a Georgia Power company-owned coal-fired power plant. At this time, the specific company-owned facility has not yet been determined.

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 1**

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**STF-L&A-1-16**

**Question:**

Section 3.3 of the Environmental Compliance Strategy states, "The research center will be a collaborative project with other electric power utilities supporting construction and operations through funding from the EPRI." What portion of the funding will be from EPRI for construction and operation of the center?

**Response:**

EPRI is establishing a supplemental project for the construction and operation of the center and will solicit other utilities to join the project and commit funding. The key milestones, detailed deliverables, location, and project constraints are under development; therefore, actual construction and operation budgets, as well as the corresponding allocations, have not been determined.

EXHIBIT\_\_(RS/RT-13)

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NOS. 42310 & 42311**

**Data Request No. STF-L&A-1-11**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS A TRADE SECRET**

As part of Georgia Power Company's 2019 Integrated Resource Plan filed in Docket No. 42310 ("2019 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 42311 ("2019 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-L&A-1-11 ("Response"). In the Response, the Company has provided details of its research and development activities. All of such information (the "Information") constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains details on the Company's research and development activities and is the result of expenditures on the part of the Company. Publicly disclosing these activities allows competitors to have access to such information without similarly expending resources, putting the Company at an economic disadvantage. Furthermore, competitors of the Company are generally not required to publicly disclose similar information, and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-L&A Data Request Set Number 1**

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**STF-L&A-1-11**

**Question:**

Refer to Section 3.3 of the Environmental Compliance Strategy wherein the Company states it "... is developing a center for beneficial use of harvested CCR ... [and] aims to develop new technologies or processes that drive downward cost pressure associated with beneficiation and expand current and potential markets. Provide a copy of all documents, studies and analysis supporting the Company's decision to develop the center.

**Response:**

Currently, the Company sells the majority of all CCR generated for beneficial reuse, primarily into the concrete market. However, if coal generation continues to decline, beneficial reuse of harvested CCR will grow in importance as the amount reused in current markets approaches and surpasses production levels. Emerging technologies and products for beneficial reuse of CCR, such as in high ash building products and porcelain tile, also have the potential to increase demand for CCR but require support to speed development and expand such markets for reuse. See TS STF-L&A-1-11 Attachment A. This attachment is being provided in electronic format only.

Yet, use of harvested CCR is in its infancy and, in most cases, will require some level of processing to convert it to high-value saleable products. Scientific research and larger-scale process engineering tests and demonstrations are necessary to further develop advanced processing and beneficial use technologies that can expand the use of CCR into more markets and increase the amount of stored CCR that can be harvested for beneficial use. Technology developments or enhancements to beneficially reuse CCR could ultimately allow Georgia Power to lower costs by reducing the amount of CCR stored in landfills or reclaim CCR already stored in landfills and ash ponds.

Therefore, in partnership with EPRI and other electric power utilities, the Company is developing a center for beneficial use of harvested CCR. See TS STF-L&A-1-11 Attachment B. The objectives of the center will be to review commercial beneficiation processes, understand performance of reuse products, and develop realistic cost profiles. This attachment is being provided in electronic format only.



PD STF-L&A-1-11 Attachment A

**PUBLIC DISCLOSURE**

This document is being redacted in its entirety.

PD STF-L&A-1-11 Attachment B

**PUBLIC DISCLOSURE**

This document is being redacted in its entirety.

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NOS. 42310 & 42311**

**Data Request No. STF-PIA-9-4**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS A TRADE SECRET**

As part of Georgia Power Company's 2019 Integrated Resource Plan filed in Docket No. 42310 ("2019 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 42311 ("2019 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-PIA-9-4 ("Response"). In the Response, the Company has provided detailed projections of capital expenditures by individual environmental controls and operation and maintenance costs for specific environmental items. All of such information (the "Information") constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, if the Information was revealed to the public, suppliers of environmental control equipment and vendors of operation and maintenance materials, such as limestone and ammonia, could use the Information to tailor proposals according to the Company's expected costs to the detriment of customers. Georgia Power's ability to negotiate the optimum price and contract terms and conditions would be undermined if competitors and suppliers had access to the projections contained in the information. Ultimately, the customers of Georgia Power would be harmed by higher rates if the Information was publicly available. Lastly, the Company's competitors are not required to disclose this information, and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**Docket Nos. 42310 & 42311**  
**Georgia Power Company's 2019 IRP and 2019 DSM Application**  
**STF-PIA Data Request Set Number 9**

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**STF-PIA-9-4**

**Question:**

What Contingency amounts are included in the CapEx budgets (example STF-JKA-1-31 Attachment A6 contingency 25%)?

- a. If contingency is imbedded in the budgets, provide the total amount of contingency in dollars for each item in the "Cap Ex Projections" tab of STF-L&A-1-8.

**Response:**

As discussed in the Company's response to STF-PIA-9-1, the Company's annual strategy development processes provides the necessary flexibility to develop and refine the environmental compliance strategy. Incorporating project contingency is a common industry practice that is necessary and appropriate to account for inherent project-specific risk exposure associated with complex projects. As a project moves into construction, and more certainty is gained, the level of contingency needed to account for risk exposure is reduced.

Please see TS STF-PIA-9-4 Attachment for project contingencies. This attachment is being provided in electronic format only.

[illegible]

[illegible]

[illegible]

EXHIBIT\_\_(RS/RT-14)



**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NO. 42516**

**Data Request No. STF-L&A-12-1**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS TRADE SECRET**

As part of Georgia Power Company's 2019 Rate Case filed in Docket No. 42516, Georgia Power Company (the "Company") submits to the Georgia Public Service Commission (the "Commission") its response to STF-L&A-12-1 ("Response"). In the Response, the Company has provided detailed financial information regarding the estimated future expenditures for ash pond and landfill closures (the "Information"). Such Information constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable, proposals according to the Company's expected costs to the detriment of the Company and its customers. Lastly, the Company's competitors are not required to disclose this type of information, and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Company and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**PUBLIC DISCLOSURE**

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-12**

**STF-L&A-12-1**

Question:

ECCR. Refer to Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5.

- a. For each amount on lines 1-6, show in detail the 13-month average balances that were used.
- b. Identify the July 31, 2019 actual amounts for each of the following ECCR amounts:
  - 1) Retail Electric Plant in Service
  - 2) Accumulated Depreciation
  - 3) Net Plant in Service
  - 4) Environmental Regulatory Assets
  - 5) Accumulated Deferred Income Taxes
- c. Provide an itemized listing of the ECCR Regulatory Assets.
- d. Are any amounts related to CCR AROs or CCR compliance capital expenditures included in the ECCR Total Rate Base amounts on line 6 of Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5? If so, identify the CCR amounts that are included in each amount on lines 1-6 of Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5.
- e. Show in detail all calculations that are described in note b on Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5 and provide the related Excel files containing those calculation details.
- f. Show in detail all calculations that are described in note c on Exhibit (DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5 and provide the related Excel files containing those calculation details.
- g. Show in detail how the Depreciation Expense amounts on Exhibit DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5, line 10, are derived by applying depreciation rates to Retail ECCR Electric Plant in Service amounts, such as the Retail Electric Plant in Service amounts shown on line 1. Include all supporting detail and Excel files showing such calculations.
- h. How much estimated capital expenditures for "contingency" are included in each of the amounts for Retail Electric Plant in Service on line 1 of Exhibit DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5? Identify the amounts and show in detail how the "contingency" amounts can be reconciled to the

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**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-12**

contingency amounts for projected capital expenditures that are listed in the TRADE SECRET Excel Attachment to response to STF-L&A-10-4.

- i. How much for estimated capital expenditures "contingency" estimates has been included on the following line items of Exhibit DPP/SPA/MBR-1, Schedule 3 ECCR), page 4 of 5:
- 1) line 1 - Accumulated Depreciation
  - 2) line 4 - Environmental Regulatory Liability
  - 3) line 5 - ADIT
  - 4) line 9 - Environmental Remediation Accrual
  - 5) line 10 - Depreciation Expense
  - 6) line 11 - Environmental Regulatory Assets Amortization
  - 7) line 13 - Federal income taxes
  - 8) line 14 - State income taxes

Response:

- a. Please see the Company's response to STF-L&A-3-6.
- b. Please see below for actual balances in ECCR as of July 31, 2019.

(Amounts in Thousands)

Retail Electric Plant in Service	\$4,363,059
Accumulated Depreciation	(\$859,866)
Net Plant in Service	\$3,503,193
Environmental Regulatory Assets	\$693,833
Accumulated Deferred Income Taxes	(\$885,055)

- c. Please see the Company's response to STF-L&A-3-6.
- d. CCR ARO expenditures are not included in the ECCR tariff.

The Company is providing projected annual closures to Plant-in-Service related to CCR compliance capital expenditures in the table below. Please note, these amounts do not reflect 13-month averages nor cumulative balances. Further, the amounts represent total Company including wholesale. The Company has not performed an analysis to determine the impact of the CCR compliance costs in ECCR Total Rate Base on a stand-alone basis.

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**GEORGIA POWER COMPANY**  
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**Staff Data Request No. STF-L&A-12**

(Amounts in Thousands)

Test Period	2020	2021	2022
REDACTED	REDACTED	REDACTED	REDACTED

- e. Please see the Company's response to STF-L&A-3-6.
- f. Please see the Company's response to STF-L&A-3-6.
- g. Please see the Company's response to STF-L&A-3-6.
- h. The Company is providing projected annual closures to Plant-in-Service related to capital expenditure contingency estimates in Attachment STF-L&A-12-1. The amounts listed in the attachment are the closures from STF-L&A-1-8 Attachment in the Company's 2019 IRP for the corresponding projects in Attachment STF-L&A-10-4 that are included within the rate case period.

Please note, these amounts do not reflect 13-month averages nor cumulative balances. Further, the amounts represent total Company including wholesale. The Company has not performed an analysis to determine the impact of the capital expenditure contingency estimates in ECCR Total Rate Base on a stand-alone basis. In addition, capital expenditure contingency estimates for ECCR capital projects are not readily available on a monthly basis and therefore the Company is not able to provide the test period amount.

- i.
  - 1) The Company has not performed this analysis.
  - 2) There are no capital expenditure contingency estimates included in Environmental Regulatory Assets.
  - 3) The Company has not performed this analysis.
  - 4) There are no capital expenditure contingency estimates included in Environmental Remediation Accrual.
  - 5) The Company has not performed this analysis.
  - 6) There are no capital expenditure contingency estimates included in Environmental Regulatory Assets Amortization.
  - 7) The Company has not performed this analysis.

**PUBLIC DISCLOSURE**

**GEORGIA POWER COMPANY  
Docket No. 42516  
Georgia Power Company's 2019 Rate Case  
Staff Data Request No. STF-L&A-12**

- 8) The Company has not performed this analysis.

**ECCR Contingency Closures to Plant in Service**  
**(Amounts in thousands)**

Project	Control Type	2020	2021	2022
REDACTED	Baghouses(MATS)	REDACTED	REDACTED	REDACTED
REDACTED	Baghouses(MATS)	REDACTED	REDACTED	REDACTED
REDACTED	Baghouse	REDACTED	REDACTED	REDACTED
REDACTED	Baghouse	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	All Other Controls	REDACTED	REDACTED	REDACTED
REDACTED	Baghouse	REDACTED	REDACTED	REDACTED
REDACTED	Baghouse	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	scr	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	All Other Controls	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	scr	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	All Other Controls	REDACTED	REDACTED	REDACTED
REDACTED	All Other Controls	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Scrubbers	REDACTED	REDACTED	REDACTED
REDACTED	Waste Water Treatment	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	SCR	REDACTED	REDACTED	REDACTED
REDACTED	All Other Controls	REDACTED	REDACTED	REDACTED
REDACTED	all other controls	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Landfill Construction	REDACTED	REDACTED	REDACTED
REDACTED	Landfill Construction	REDACTED	REDACTED	REDACTED
REDACTED	Waste Water Treatment	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Waste Water Treatment	REDACTED	REDACTED	REDACTED
REDACTED	Ash Management	REDACTED	REDACTED	REDACTED
REDACTED	Waste Water Treatment	REDACTED	REDACTED	REDACTED
REDACTED	Waste Water Treatment	REDACTED	REDACTED	REDACTED
REDACTED	Waste Water Treatment	REDACTED	REDACTED	REDACTED
REDACTED	Total	REDACTED	REDACTED	REDACTED

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NO. 42516**

**Staff Informal Data Request**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS TRADE SECRET**

As part of Georgia Power Company's 2019 Rate Case filed in Docket No. 42516, Georgia Power Company (the "Company") submits to the Georgia Public Service Commission (the "Commission") its response to Staff's Informal Data Request ("Response"). In the Response, the Company has provided detailed financial information regarding the estimated future expenditures for ash pond and landfill closures (the "Information"). Such Information constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable, proposals according to the Company's expected costs to the detriment of the Company and its customers. Lastly, the Company's competitors are not required to disclose this type of information, and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Company and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**PUBLIC DISCLOSURE**

**Informal Data Request Follow-up to Rate Case DR L&A-12-1**

**Question:**

Attachment STF-L&A-12-1 shows “ECCR Contingency Closures to Plant in Service” of only \$2.9 million for 2020-2022.

Staff would like the Company to identify how much contingency is in the ECCR amounts embedded in the cost estimates for the test year and each alternative rate plan year (2020, 2021, 2022).

Please provide Company’s best estimates and explain how the estimates were derived.

In the IRP, the Company identified \$92.9 million of ECCR contingency (per STF-PIA-9-4).

**Response:**

In the IRP, the Company identified \$92.9 million of ECCR contingency in its response to STF-PIA-9-4 in Docket No. 42310. The majority of the projected ECCR contingency capital expenditures provided in the Company’s response to STF-PIA-9-4 in the IRP are projected to be placed in service (and reflected in rate base) in years beyond 2022. As a result, the majority of the \$92.9 million of ECCR contingency is excluded from the projected revenue requirement in this filing. The Company’s response to STF-L&A-10-4 contains the ECCR contingency capital expenditures included in the rate case budget. Please note, this amount is approximately \$10 million lower than the \$92.9 million of ECCR contingency identified in STF-PIA-9-4 in the IRP due to removal of two projects that are no longer moving forward.

The \$2.9 million of “ECCR Contingency Closures to Plant in Service” provided in Attachment STF-L&A-12-1 and shown below reflects the ECCR contingency dollars that cover projects projected to close during the rate case period (2020-2022).

Year	2020	2021	2022
Dollars (in thousands)	REDACTED	REDACTED	REDACTED

As stated in the Company’s response to STF-L&A-12-1, the \$2.9 million of ECCR contingency closures are embedded in the cost estimates included in the Company’s filing on page 4 of Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 3 ECCR). In addition, as described in the Company’s response to part (h) in STF-L&A-12-1, the \$2.9 million does not reflect a 13-month average or cumulative balances and is representative of Total Company, including wholesale. The Company cannot provide a test period amount because capital expenditure contingency estimates for ECCR capital projects are not readily available on a monthly basis.



In the Company's response to STF-L&A-12-7, the Company provided a summary of how the contingency for ECCR projects that are projected to close during this rate case period (2020-2022) were derived. The Company undertakes significant efforts to perform an analysis to determine contingency for these projects. This process involves considering each project to evaluate the engineering, schedules, construction work, and costs associated with these activities. The contingency evaluation involves a comprehensive review of these projects, including the major work associated. The projects are then assigned risk percentages based on confidence level in quantities, labor productivity, material pricing, and subcontractors.

The contingency amounts included within Exhibit \_\_ (DPP/SPA/MPR-1, Schedule 3 ECCR) are provided in Attachment STF-L&A-12-1 in the Company's response to STF-L&A-12-1 and have differing levels of contingency based off the status, stage, and type of project. For these ECCR projects, the confidence level typically ranges from P50 to P80; however, as discussed above, this range is project specific and may not be reflective for all projects during their varying stages.

**Staff Informal Follow-Up Questions to STF-L&A-12-1 Related to ECCR Contingency  
Amounts**

Data redacted in its entirety.

Attachment ECCR Contingency

**GEORGIA POWER COMPANY**  
**ENVIRONMENTAL INVESTMENT AND EXPENSES (a)**  
**PROJECTED CONTINGENCY COSTS**  
**FOR THE TWELVE MONTH PERIODS ENDING DECEMBER 31, 2020-2022 & TEST PERIOD**  
**(AMOUNTS IN THOUSANDS)**

Description	Test Period (b)	Calendar Years Ending		
		2020	2021	2022
Retail Electric Plant in Service				
Accumulated Depreciation				
Net Plant in Service				
Accumulated Deferred Income Taxes				
Total Rate Base				
Depreciation Expense				

Note: Details may not add to totals due to rounding.

[REDACTED]

[REDACTED]

[REDACTED]

EXHIBIT\_\_(RS/RT-15)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-47**

Question:

With regard to property tax true-ups for both Georgia Power Company please provide the following information:

- a. In the same format and detail as per the response to STF-RCS-1-35 in Docket No. 36989, provide the actual property tax valuation true-ups that have been incurred and booked by GPC for each year from 2017 through 2018 and for the 12-month period ended 5/31/19.
- b. Explain the reasons for these property tax true-ups and explain whether such true-ups can be expected to continue in the future. In addition, explain how these tax true ups are treated for book purposes and how they have impacted the Company's property tax expenses for each of the years 2017 through 2018.
- c. Do the budgeted property tax expenses for the forecasted test year incorporate any of such property tax valuation true-ups expected for the projected test year? If so, identify the amount of such valuation true up.

Response:

- a. Please see Attachment STF-L&A-1-47 for a listing of 2017 through 5/31/2019 property tax true-ups.
- b. Property taxes are accrued based on the annual budget estimates for the current year. Throughout the year as the actual millage rates and assessed values become available, the estimated amounts are true-up to approximate the actual property taxes assessed to be paid. Property tax true-ups are generally recorded as a debit/credit to Property Tax Expense (FERC 408) and a corresponding debit/credit to the Property Tax Payable (FERC 236). In 2018, there was a reduction of \$1.1 million for the 2017 property tax true-up related to the 241 GPC Headquarters building, which was allocated between O&M and capital accounts.
- c. No, the budget does not reflect any property tax valuation true-ups since the true-ups are not known until actual data become available.

GEORGIA POWER COMPANY  
TAXES-OTHER-THAN-INCOME-TAXES  
GEORGIA REAL PROPERTY TAX TRUE-UPS

YEAR RECORDED ON BOOKS	PROPERTY TAX YEAR 2016	PROPERTY TAX YEAR 2017	PROPERTY TAX YEAR 2018	TOTALS
2017	\$ (533,293)	\$ (3,200,000)		\$ (3,733,293)
2018		(1,670,002)	2,080,833	410,832
5/31/2019		1,017	250,597	251,614
TOTALS	<u>\$ (533,293)</u>	<u>\$ (4,868,985)</u>	<u>\$ 2,331,430</u>	<u>\$ (3,070,848)</u>

GEORGIA POWER COMPANY  
TAXES-OTHER-THAN-INCOME-TAXES  
GEORGIA REAL PROPERTY TAX TRUE-UPS

YEAR RECORDED ON BOOKS	PROPERTY TAX YEAR 2009	PROPERTY TAX YEAR 2010	PROPERTY TAX YEAR 2011	PROPERTY TAX YEAR 2012	PROPERTY TAX YEAR 2013	PROPERTY TAX YEAR 2014	PROPERTY TAX YEAR 2015	PROPERTY TAX YEAR 2016	TOTALS
2012	\$ (105,638)	\$ (56,679)	\$ (347,671)						(509,988)
2013				(609,302)	(2,351,510)				(2,960,812)
2014				(1,187,471)	(2,705,775)				(3,893,246)
2015						(4,012,153)			(4,012,153)
2016							320,798	(53,868)	266,930
TOTALS	\$ (105,638)	\$ (56,679)	\$ (347,671)	\$ (1,796,773)	\$ (5,057,285)	\$ (4,012,153)	\$ 320,798	\$ (53,868)	\$ (11,109,268)

**GEORGIA POWER COMPANY**  
**Docket No. 36989**  
**Georgia Power Company's 2013 Rate Case**  
**Staff Data Request No STF-RCS-1**

**STF-RCS-1-35**

Question:

With regard to property tax true-ups for both GPC and SEPCO please provide the following information:

- a. In the same format and detail as per the response to STF-HC-1-35 in Docket No. 31958-U, provide the actual property tax valuation true-ups that have been incurred and booked by GPC and SEPCO for each year from 2002 through 2012 and for the 12-month period ended 5/31/13.
- b. Explain the reasons for these property tax true-ups and explain whether such true-ups can be expected to continue in the future. In addition, explain how these tax true ups are treated for book purposes and how they have impacted the Company's property tax expenses for each of the years 2002 through 2012.
- c. Do the budgeted property tax expenses for the forecasted test year incorporate any of such property tax valuation true-ups expected for the projected test year? If so, identify the amount of such valuation true up.

Response:

- a. Refer to Attachment STF-RCS-1-35 for a listing of 2002 through 5/31/2013 true-ups of Real Property tax.
- b. Property taxes are based on the annual budget estimates for the current accounting period. Throughout the year as the facts become known (actual millage rates and actual assessed values), the estimated amounts are adjusted to approximate what is expected to be the actual property taxes assessed and to be paid. Property taxes are recorded as a debit to Property Tax Expense (FERC A/C 408, construction accounts, clearing accounts, and nonutility accounts) and a credit to the Property Tax Payable (FERC A/C 236). These true-ups adjust this expense/accrual entry by debiting or crediting Property Tax Payable (FERC A/C 236) and crediting or debiting Property Tax Expense (FERC A/C 408) or other accounts originally charged as appropriate.
- c. No, the budget does not reflect any property tax valuation true-ups.

Contact Person: David Meiselman



EXHIBIT\_\_(RS/RT-16)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-129**

Question:

Identify all costs and revenue for electric vehicle charging stations in rate base, revenue and operating expense for forecasted test year and for calendar years 2019-2022, by account.

Response:

Please see the table below for amounts included in the forecasted test year and for the forecasted calendar years 2020-2022 related to the electric vehicle charging stations by FERC account. The Company did not prepare the information requested above for calendar year 2019 in this filing.

<b>EV Charging Stations (Amounts in Thousands)</b>					
<b>Rate Base</b>	<b>FERC Account</b>	<b>Test Year</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>
<b>(13-month average):</b>					
Plant in Service	101	\$4,094	\$4,933	\$6,933	\$8,933
Accumulated Depreciation	108	(291)	(342)	(505)	(721)
Materials & Supplies	154	24	24	24	24
ADITs	282	(639)	(713)	(949)	(1,243)
<b>Net Rate Base</b>		<u>\$3,188</u>	<u>\$3,902</u>	<u>\$5,503</u>	<u>\$6,993</u>
<b>Operating Income:</b>					
Revenue	456	\$(108)	\$(115)	\$(120)	\$(123)
O&M Expenses	908	\$325	\$334	\$342	\$351
Depreciation Expense	403	\$88	\$135	\$189	\$243

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-5**

**STF-L&A-5-33**

Question:

Refer to the Poroch/Adams/Robinson testimony at pages 47-48

- a. Provide the business case for the Company's Electric Transportation Activities.
- b. Provide the detailed plan for the \$6 million investment the Company proposes over the term of the ARP by year, 2020, 2021 and 2022.
- c. Since the end of the 2014 Pilot program, has the Company done any evaluation/redesign of its program to structure it so that it provides benefits to customers? If so, provide any studies or evaluations conducted by the Company. If it has not conducted any study to support additional investment in these activities, provide an explanation as to why not.

Response:

- a. Georgia Power's electric transportation ("ET") strategy is built on foundational activities that support the influencing factors for electric vehicle ("EV") adoption of education, economics of ownership, availability of charging infrastructure and driver convenience.

Georgia Power's on-road and non-road ET programs enable and support our residential, commercial and industrial customers transitioning into the transportation and mobility electrification space. Focusing on these areas positions Georgia Power as a trusted resource for educating, demonstrating and facilitating the advantages of electric transportation for both the movement of goods and the movement of people. The Business case/strategic focus areas are as follows:

1. Customer Education
2. EV Charging Infrastructure
  - a. Rebates
  - b. Public (Company-owned and Partnerships)
3. Fleet Electrification

Please see Attachment STF-L&A-5-33 for summary details of Georgia Power's activities in the strategic areas noted above.

- b. Georgia Power's proposed investment of \$6 million over the term of the ARP in 2020, 2021 and 2022 will result in significant infrastructure improvements. Assuming \$75,000 per new direct current fast charger ("DCFC") installation, the program can result in roughly 25 additional chargers per year for a total of 75 DCFC chargers over three years. Georgia Power plans to meet the increasing need for charging infrastructure – EV

registrations increased 135% in 2018 from 2017 and Lyft EV drivers logged more than 1,100,000 miles over a six-month span in 2019 – with a three-pronged approach:

**1. Install chargers in high-traffic and high-utilization areas around metro Atlanta and mid-sized Georgia metros.**

In January 2019, Lyft began implementing 50 all-electric Chevy Bolts into its Express Drive program in Atlanta, which allows drivers without vehicles to rent a car from Lyft and earn money on its ridesharing platform. In the first six months of the program, Lyft EV drivers logged more than 45,000 rides. Lyft EV drivers are almost exclusively reliant on the public fast-charging infrastructure to perform their jobs, creating much heavier demand for infrastructure. The Lyft program, combined with an uptick in EV registrations among the general public, has created lengthy wait times at Georgia Power DCFCs in some instances and lowered the overall confidence that chargers are available when needed. Georgia Power plans to work with Lyft to identify key rideshare travel corridors most optimal for charging locations. Based on utilization data from the Georgia Power community DCFCs and data from Lyft, the area around Hartsfield-Jackson International Airport – the No. 1 destination for Lyft rides in Georgia – critically needs additional charging infrastructure.

Additionally, 6,246 plug-in EVs were registered in Georgia in 2018, up from 2,654 in 2017. According to registration data provided by the Electric Power Research Institute (EPRI), mid-sized cities like Athens, Savannah and Columbus are beginning to see an increase in their respective EV populations.

**2. Expand community DC fast chargers in strategic corridors throughout the state**

Gaps still exist among U.S. Department of Transportation-designated alternative-fuel corridors in Georgia, notably, on I-75 between Cordele and Valdosta and I-95 between Savannah and Brunswick. EV trips to popular destinations in North Georgia are also limited by lack of charging infrastructure. Driving habits among EV drivers are also expected to change with up to 240 miles of driving range in new EV models, giving them confidence to take their EVs on longer trips in Georgia. With increased battery range and further reductions in battery costs as the technologies mature, EVs should achieve price parity with internal combustion engine alternatives. Since 2010, the average cost of lithium-ion batteries per kilowatt-hour has fallen by 85%.

**3. Increase charger availability in low-income areas**

According to Lyft data, many Lyft EV renters live in zip codes with a median household income below that of Georgia's median household income. Many of these drivers live in multi-unit dwellings and do not have access to home charging, requiring trips to a fast charger at the beginning or end of a shift. However, compared to more affluent neighborhoods in North Metro Atlanta, South Metro has a dearth of charging infrastructure with few indicators that the public market is willing to invest in disadvantaged communities. Georgia Power plans to fill these gaps and enable these drivers to continue to make a living.

The electric rideshare market is expected to grow, putting an even larger emphasis on increasing charging infrastructure. Both Uber and Lyft have stated plans to increase electric miles driven in the United States over the next few years.

- c. Since the end of the two-year Pilot program ending December 2016, the Company completed a pilot evaluation and filed it with the Commission on August 4, 2017. Key insights from the Pilot as listed below have continued to shape current and future ET strategies.
  1. Education and awareness efforts increased awareness and purchase consideration and helped influence market adoption.
    - o Experiential education (e.g. testimonies, “ride & drives”, etc.) were the most successful aspects in providing drivers with real-world EV experience.
    - o Social and digital media experienced the highest consumer engagement amongst the channels used in the ET Pilot.
  2. Rebates (workplace and residential) supported EV adoption and provided benefits to non-participants as shown by the positive RIM Test results and businesses valued EV charging as an amenity driving business rebate adoption.
  3. Community Infrastructure, though critical for market growth, is capital intensive and the usage fees collected from users likely will fall short of fully paying for the capital investment. Due to the changing market in Georgia, the Company suspended installing Community chargers at that time.
  4. A favorable EV environment (incentives, policy, high occupancy vehicles/high occupancy toll (“HOV” and “HOT”) lane access, etc.) significantly increases adoption and is impactful to grow the EV market.

Georgia Power has not completed any additional studies beyond the Pilot evaluation. Nevertheless, the Company applied lessons learned from the Pilot evaluation and continues to closely monitor the usage of the Company’s existing charging network as well as broad areas of the EV market including: EPRI’s on-road EV sales projections; technology advancements (battery range and cost, decrease in charging time, equipment replacement cost savings, battery storage); the evolution and mass market production of EV models of all sizes and uses; and market disruptors such as ride-share and autonomous vehicles. The Company also plans to participate in research and development efforts through industry membership (EPRI, Edison Electric Institute, Clean Cities Georgia, Alliance for Transportation Electrification and Electric Drive Transportation Association), Southern Company Services research and development and other leadership opportunities.



# Electric Transportation Strategy

# Georgia Power's Electric Transportation Strategy

## ***Objective***

Be the trusted source for educating, facilitating and demonstrating the advantages of electrification for our customers as they transition to electric transportation

## ***Key Features of Georgia Power's ET Program***

- Includes all customer classes (Residential, Commercial and Industrial)
- Applies to on-road and off-road technologies

## **Strategic Areas of Focus**

1. Customer education and outreach
2. Electric vehicle charging infrastructure
3. Fleet electrification

# Customer Education and Outreach

## ***Objective***

Leverage Georgia Power's expertise to educate customers on the benefits of electric transportation for their specific needs

## **Focus Areas**

- One-on-one customer consultation
- Experiential events
- Promotion of ET through a variety of media
  - Social media
  - Digital Media campaigns
  - Print, bill inserts, radio & TV



# EV Charging Infrastructure

## **Objective**

Ensure customers in the electric transportation space have a robust and reliable charging network throughout Georgia

## **Focus Areas**

- Rim passing rebate programs
  - Residential charger rebates (\$250/charger)
  - EV ready home rebates (\$100/EV plug)
  - Workplace charging rebates (\$500/charger)
- Georgia Power’s community charging network
  - 37 community charging islands
  - Includes both DC fast chargers and level 2 chargers
- Increasing charger installations through partnerships

# Fleet Electrification

## ***Objective***

Assist customers in identifying which electric transportation solution best supports their needs for both on-road and off-road ET applications

## **Process**

1. Customer consultation
2. Suitability assessment (may include demonstration in customers operation)
3. Data collections & analysis
4. Recommendations for potential benefits in the areas of:
  - Fuel
  - Maintenance

EXHIBIT\_\_(RS/RT-17)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-60**

Question:

Please provide all expenses included in the above-the-line for each forecasted year, 2020 through 2022, related to financial services rendered to the Company's top executives, and the top executives of the parent company and affiliates such as SCS and SNOC, such as for financial planning, estate planning, investment advice, tax planning and preparation, etc. Show the total amounts for each executive and also show the amounts allocated to Georgia Power Company and the expenses for Georgia Power Company by account.

Response:

The Executive Financial Planning Program is available for exempt grade level 10 and above employees. The program is budgeted as a component within Miscellaneous Benefits at the company level, but not specifically broken out for individual positions. The budget is held flat with no escalation for future years.

	<u>Test Year</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>
GPC – Directly incurred – (FERC 926)	\$164,410	\$164,410	\$164,410	\$164,410
SCS – Allocated to GPC – (* allocated)	180,000	180,000	180,000	180,000
SNC – Allocated to GPC – GPC% – (FERC 524)	69,964	70,145	67,430	54,756
GPC Executive Financial Planning Cost	\$414,374	\$414,555	\$411,840	\$399,166

\* SCS costs are allocated across multiple FERC accounts

EXHIBIT\_\_(RS/RT-18)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-32**

Question:

Similar to the Company's response to STF-RCS-1-21 in Docket No. 36989, please provide the following information for the current rate case:

- a. If any interest is earned by GPC on its test period average minimum bank balance, please provide the annual amount of this interest. Include the calculations and explain whether this interest income has been reflected as above-the-line income in the forecasted test year.
- b. Annualized savings in fees from interest credits earned on other balances which effectively serve to offset certain banking and administrative fees. Also, explain whether such interest credits have been reflected for ratemaking purposes in this case.

Response:

- a. The Company earns interest credits on minimum bank balances which offset bank fees. In 2018, the Company earned interest credits provided by the respective bank's earnings credit rates to offset approximately \$600 thousand in bank fees, which would have been recorded above-the-line to FERC account 923-00010. No amount of interest credits on the minimum bank balances are budgeted for the test period ending July 31, 2020.
- b. There are no other balances for which the Company earns interest credits to offset banking and administrative fees.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-4**

**STF-L&A-4-47**

Question:

Refer to DPA-SPA-MBR-2, page 24. Show in detail how each of the following items in both columns "12 Mos Ended 07/31/2020" and "12 Mos Ended 12/31/2018" in Footnote AL/ was derived and include complete supporting calculations and workpapers:

- a. Minimum Bank Balances
- b. Prepayments

Response:

Please see the Company's response to STF-L&A-1-31 for the 13-month average ending December 31, 2018 and July 31, 2020.

Please see Attachment STF-L&A-4-47 for the calculation of minimum bank balances for the test year.

\$ in Thousands

<u>Test Year</u>	<u>Minimum Bank Balance Calculation</u>	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>	<u>Average</u>
Projected Minimum Bank Balance is calculated based on an actual 3-year average of balances (2016-2018)															
2016		38,428	34,369	32,788	33,887	28,813	25,673	24,543	34,021	38,806	61,523	34,160	48,391	79,538	39,611
2017		79,538	22,591	38,522	64,206	83,409	57,798	61,706	50,889	46,177	58,616	61,264	50,596	51,839	55,935
2018		51,839	52,444	50,736	57,822	56,134	48,753	39,825	42,604	46,764	55,029	33,756	35,762	53,078	48,042
<b>3-year Average</b>															<b>47,863</b>



EXHIBIT\_\_(RS/RT-19)

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NO. 42516**

**Data Request No. STF-L&A-11-19**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS TRADE SECRET**

As part of Georgia Power Company's 2019 Rate Case filed in Docket No. 42516, Georgia Power Company (the "Company") submits to the Georgia Public Service Commission (the "Commission") its response to STF-L&A-11-19 ("Response"). In the Response, the Company has provided non-public, negotiated earnings credit rates (the "Information"). Such Information constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details on the credit rates the Company negotiated that are applied to derive the amount of earnings credits the Company earns from various banks for cash balances. Disclosure of the Information could harm the Company in its efforts to obtain optimal pricing in current or future negotiations.

The Information is subject to substantial procedures to maintain its secrecy. Only select Company and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**PUBLIC DISCLOSURE**

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-11**

**STF-L&A-11-19**

Question:

Interest credits on minimum bank balances. Refer to the response to STF-L&A-1-32.

- a. Identify the average 2018 minimum bank balances.
- b. Identify the applicable interest rates in 2018.
- c. Identify the average minimum bank balances forecasted for each year, 2019, 2020, 2021 and 2022.
- d. Identify the applicable forecasted interest rates for each year, 2019, 2020, 2021 and 2022.
- e. Were any interest credits budgeted for 2019, 2020, 2021 or 2022? If not, explain fully why not. If so, identify the amounts of interest credits budgeted for each year.
- f. What is the actual amount of interest credits for the six-month period through June 30, 2019?
- g. What is the actual amount of interest credits for the 12-month period through June 30, 2019?

Response:

- a. Please see the Company's response to STF-L&A-4-47.
- b. In 2018, the earnings credit rates averaged between REDACTED and REDACTED for Bank of America and between REDACTED and REDACTED for Wells Fargo.
- c. The average minimum bank balances projected from January 2019 through December 2022 are \$47.9 million. The amount is based on a 3-year historical average as calculated in the Company's response to STF-L&A-4-47.
- d. The forecasted earnings credit rates in relation to the interest credits on the minimum bank balances fluctuate based on market conditions and the minimum bank balance on a total system basis. Therefore, no interest credits were budgeted for 2019 through 2022.
- e. Please see the Company's response to part 'd'.

**PUBLIC DISCLOSURE**

**GEORGIA POWER COMPANY  
Docket No. 42516  
Georgia Power Company's 2019 Rate Case  
Staff Data Request No. STF-L&A-11**

- f. The actual amount of interest credits for the six-month period through June 30, 2019 is approximately \$157 thousand.
- g. The actual amount of interest credits for the 12-month period through June 30, 2019 is approximately \$275 thousand.

EXHIBIT\_\_(RS/RT-20)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-125**

Question:

For 2018 what amounts of Production Tax Credits were claimed by the Company for:

- a. solar generation
- b. wind generation
- c. hydro generation
- d. any other type of generation or renewable purchased power qualifying for PTCs?

Response:

The amount recognized in 2018 for Hydro Production Tax Credits was \$40,534. The Company did not have any other Production Tax Credits in 2018.

Contact: Richard Dodd

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-126**

Question:

What amounts of renewable generation and Production Tax Credits were projected to be claimed by the Company in the forecasted test year and for calendar years 2019-2022 for each of the following:

- a. solar generation
- b. wind generation
- c. hydro generation
- d. any other type of generation or renewable purchased power qualifying for PTCs?

Response:

The Company projects to receive Production Tax Credits for Vogtle Units 3 and 4 of \$6.5 million and \$70.4 million in 2021 and 2022, respectively. However, the in-service costs of Vogtle Units 3 and 4, including production tax credits, are excluded from the Company's filing as shown in Exhibit\_\_(DPP/SPA/MBR-6, Schedule 3). The Company does not project to receive any other Production Tax Credits for the projected years.

Contact: Richard Dodd

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-127**

Question:

As of 12/31/2017 and 12/31/2018 did the Company have any Production Tax Credits in a carry-forward position? If so, identify, quantify and explain the amounts of any PTC carry-forwards as of each date.

Response:

The Company had Renewable Production Tax Credits related to the hydro units in a carryforward position in the amount of \$703,659 and \$744,193 for 12/31/2017 and 12/31/2018, respectively.

Contact: Richard Dodd



**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NO. 42516**

**Data Request No. STF-L&A-13-4**

**Basis for the Assertion that the Information  
Submitted is a Trade Secret**

As part of Georgia Power's 2019 Rate Case filed in Docket 42516, Georgia Power Company (the "Company") submits to the Georgia Public Service Commission (the "Commission") its response to STF-L&A-13-4. In the response, the Company has included projected hydro generation (the "Information"). Such Information constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information pertains to the Company's forecasts and projections regarding the output of the Company's hydro generation assets. Disclosure of the Information would provide extensive insight into the future plans and projections of the Company. If revealed to the public, a generation wholesaler or power marketer could use the Information to tailor proposals with the intention of pricing products that could undermine the Company's market position. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company and its customers. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Company and Southern Company personnel and their legal counsel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**PUBLIC DISCLOSURE**

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-13**

**STF-L&A-13-4**

Question:

Production Tax Credits. Refer to the responses to STF-L&A-1-125, 126 and 127.

- a. How have the hydro production tax credits been reflected in the test year and in each plan year, 2020, 2021 and 2022?
- b. Identify the 2018 hydro production (Mwh) that produced the 2018 hydro production tax credits.
- c. Identify the amount of hydro production (Mwh) from January 1 through June 30, 2019.
- d. Identify the total anticipated amount of hydro production (Mwh) for 2019.
- e. Are any hydro production tax credits anticipated for 2019? If so how much in total, and how much are anticipated to be in a carry-forward position? If not, explain fully why not.
- f. In what years does the Company anticipate being able to use the hydro production tax credits that were in a carryforward position as of December 31, 2018 as listed in the response to STF-L&A-1-127? Show the amounts anticipated to be utilized in each year.

Response:

- a. The Company did not forecast hydro production tax credits (PTC) for the test year and years, 2020, 2021, and 2022.
- b. The 2018 hydro production that produced the 2018 hydro PTC's of \$40,534 was 3,378 Mwht.
- c. The amount of hydro production subject to PTC's for January 1 through June 30, 2019 is 651 Mwht.
- d. The amount of anticipated hydro production subject to PTC's for 2019 is REDACTED Mwht.
- e. Based on the estimated hydro production of REDACTED Mwht in 2019, the Company expects hydro PTC's of REDACTED which is expected to be included in a carry-forward position as of the end of 2019.
- f. The Company did not anticipate utilizing any of the hydro production tax credits that were in the carryforward position as of December 31, 2018 within the rate case period.

EXHIBIT\_\_(RS/RT-21)

COMMISSIONERS:

LAUREN "BUBBA" McDONALD, CHAIRMAN  
TIM G. ECHOLS  
CHUCK EATON  
H. DOUG EVERETT  
TRICIA PRIDEMORE



DEBORAH K. FLANNAGAN  
EXECUTIVE DIRECTOR

REECE McALISTER  
EXECUTIVE SECRETARY

## Georgia Public Service Commission

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**Docket No. 36989**  
**In Re: Georgia Power Company's 2013 Rate Case**

### **ORDER ON THE TAX CUTS AND JOBS ACT**

On December 22, 2017, President Trump signed into law the Tax Cuts and Jobs Act ("TCJA") which lowered the federal income tax rate from 35% to 21% as of January 1, 2018. On January 19, 2018, the Georgia Public Service Commission ("Commission") ordered Georgia Power Company (the "Company") to file comments quantifying the effects of the TCJA on the Company's cost of service and the Company's recommendations to reflect these impacts. The Company made a filing in response to the Commission's order on March 6, 2018.

After several meetings with the Company and after reviewing its calculations, the Commission Staff ("Staff") entered into an agreement with the Company to resolve this matter. A copy of the proposed Settlement is attached to this order as Attachment 1. The cover document and Exhibits 2 and 3 to the Company's March 6, 2018 filing are, and were, the work product of the Company. Staff did not agree with all positions taken therein. The proposed Settlement provided ratemaking treatment to address the effects of the TCJA on the Company's cost of service in several areas.

In reaching this settlement the Staff had concerns with the methodology used by the Company to estimate savings from the TCJA as well as the Company's rationale to support the need for an increase in the equity component as stated in the Company's March 6, 2018 filing; however, both Staff and the Company agreed that the proposed Settlement was a fair resolution of the issues.

Subsequent to the filing, the Company and Staff recommended the following proposed method for returning refunds to customers:

The first of three refunds will be issued in October 2018 allocated to customers based on their actual base billings for the period January through August 2018. Refunds will be made on a to-date calendar year basis and follow the same allocation methodology used in making Annual Surveillance Report sharing refunds. Of the \$185 million refund for 2018, approximately \$131 million will be refunded in October based on the ratio of the historical three-year average August YTD base revenues as compared to the historical three-year average annual base revenues.

The second refund will be issued in June 2019 and allocated to customers based on their actual base billings for the period September 2018 through April 2019. Approximately \$54 million of the 2018 refund plus approximately \$42 million of the \$145 million refund for 2019 will be refunded at this time. \$42 million of the total 2019 refund is based on the ratio of the historical three-year average April year-to-date base revenues as compared to the historical three-year average annual base revenues.

The third refund will be issued in February 2020 and allocated to customers based on their actual base billings for the period May 2019 through December 2019. Approximately \$103 million of the \$145 million of 2019 refund will be refunded at this time.

In total, the stipulated \$330 million will be refunded in three installments. The total refund is projected to be approximately \$70 for a 1,000 kWh residential customer.

Staff recommended (1) the Commission, in its order, clearly state that the equity level approved in this proceeding only applies for calendar years 2018 and 2019 and that Commission reserves its right to address the appropriate level of equity in the Company's capital structure in its next base rate proceeding and (2), the Company report details of the three (3) actual refunds made, by amount and customer class, as they are made to ensure customers receive the benefits of the lower taxes.

The Commission adopted Staff's recommendation at the April 3, 2018 Administrative Session.

\* \* \* \* \*

**WHEREFORE IT IS ORDERED**, that Exhibit 1, the 2018 TCJA Base Rates Settlement is hereby approved.

**ORDERED FURTHER**, that the Commission approves the recommended method for returning refunds to customers.

**ORDERED FURTHER**, that the common equity level identified in Exhibit 1 only applies for calendar years 2018 and 2019 and that the Commission reserves its right to address the appropriate level of common equity in the Company's capital structure in its next base rate proceeding.

**ORDERED FURTHER**, that Georgia Power Company shall report to the Commission details of the three tax refunds, by amount and customer class, as they are made to ensure customers receive the benefits of the lower taxes.

**ORDERED FURTHER**, that a motion for reconsideration, rehearing or oral argument or any other motion shall not stay the effective date of this Order, unless otherwise ordered by the Commission.

**ORDERED FURTHER**, that jurisdiction over this matter is expressly retained for the purpose of entering such further Order or Orders as this Commission may deem just and proper.

The above by the action of the Commission in Administrative Session on the 3rd day of April 2018.

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Reece McAlister  
Executive Secretary

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Lauren “Bubba” McDonald  
Chairman

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Date

---

Date

EXHIBIT\_\_(RS/RT-22)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-20**

Question:

Please provide a detailed listing and description of all Regulatory Liabilities that are included in the forecasted test year rate base and in each rate year and indicate where these Regulatory Liabilities are reflected (account and location on filing schedule). In addition, provide a detailed listing and description of all of the amortization expense credits associated with these Regulatory Liabilities that are included in the forecasted test year and each rate year's operating expenses and indicate where these amortization expense credits are reflected (account and location on filing schedule).

Response:

Please see Attachment STF-L&A-1-20.



**GEORGIA POWER COMPANY**  
**REGULATORY LIABILITIES IN RATE BASE**  
**FOR THE FORECASTED TEST YEAR ENDING JULY 31, 2020**  
**(AMOUNTS IN THOUSANDS)**

<b>FERC-SUB</b>	<b>Regulatory Liabilities</b>	<b>Jul-19</b>	<b>Aug-19</b>	<b>Sep-19</b>	<b>Oct-19</b>	<b>Nov-19</b>	<b>Dec-19</b>	<b>Jan-20</b>	<b>Feb-20</b>	<b>Mar-20</b>	<b>Apr-20</b>	<b>May-20</b>	<b>Jun-20</b>	<b>Jul-20</b>	<b>13 Month Average</b>	<b>Notes</b>
254-00150, 254-00151	State Tax Reform Refund	\$ (2,186)	\$ (2,606)	\$ (2,917)	\$ (3,177)	\$ (3,421)	\$ (3,694)	\$ (3,591)	\$ (3,488)	\$ (3,386)	\$ (3,283)	\$ (3,181)	\$ (3,078)	\$ (2,975)	\$ (3,153)	(a)
254-00204	Federal Tax Reform - Federal Unprotected Excess ADITs	(523,555)	(523,555)	(523,555)	(523,555)	(523,555)	(523,555)	(509,012)	(494,468)	(479,925)	(465,382)	(450,839)	(436,296)	(421,752)	(492,231)	(a)
254-00207	Federal Tax Reform - Federal Protected Excess ADITs	(104,855)	(109,315)	(113,775)	(118,235)	(122,695)	(127,155)	(123,623)	(120,091)	(116,559)	(113,027)	(109,495)	(105,963)	(102,430)	(114,401)	(a)
254-00208	Federal Tax Reform - State Unprotected Excess ADITs	(10,286)	(10,286)	(10,286)	(10,286)	(10,286)	(10,286)	(10,000)	(9,714)	(9,429)	(9,143)	(8,857)	(8,572)	(8,286)	(9,670)	(a)
254-05110 - 254-05190; 254-00121 - 254-00134	Asset Retirement Obligations (ARO) Regulatory Liability (e)	(763,485)	(751,544)	(739,603)	(727,663)	(715,722)	(703,781)	(695,455)	(687,128)	(678,802)	(670,475)	(662,148)	(653,822)	(645,495)	(699,625)	(b)

<b>FERC-SUB</b>	<b>Amortization Expenses</b>	<b>Aug-19</b>	<b>Sep-19</b>	<b>Oct-19</b>	<b>Nov-19</b>	<b>Dec-19</b>	<b>Jan-20</b>	<b>Feb-20</b>	<b>Mar-20</b>	<b>Apr-20</b>	<b>May-20</b>	<b>Jun-20</b>	<b>Jul-20</b>	<b>Total</b>	<b>Notes</b>
407-4xxxx (f)	State Tax Reform Refund	\$ -	\$ -	\$ -	\$ -	\$ -	(103)	(103)	(103)	(103)	(103)	(103)	(103)	\$ (718)	(c)
411-10111	Federal Tax Reform - Federal Unprotected Excess ADITs	-	-	-	-	-	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(101,802)	(d)
411-10111	Federal Tax Reform - Federal Protected Excess ADITs	-	-	-	-	-	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(24,725)	(d)
411-10161	Federal Tax Reform - State Unprotected Excess ADITs	-	-	-	-	-	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(2,000)	(d)

**Notes:**

The schedule above does not reflect test period normalization.

(a) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 3 - Included in Line 32, "Tax Reform Regulatory Liability"

(b) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 3 - Line 39, "ARO Regulatory Liability (254)"

(c) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 4 - Line 27, "Amortization of State Tax Reform Refund"

(d) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 4 - Included in Line 36, "Deferred Income Taxes"

(e) These amounts include the debit balance in FERC account 254 related to ARO recovery and the ARO Regulatory Liability for Nuclear Decommissioning which is excluded from retail rate base.

(f) Account has not been set up yet; proposed amortization will begin January 2020.

**GEORGIA POWER COMPANY**  
**REGULATORY LIABILITIES IN RATE BASE**  
**FOR THE FORECASTED PERIOD ENDING DECEMBER 31, 2020**  
**(AMOUNTS IN THOUSANDS)**

<b>FERC-SUB</b>	<b>Regulatory Liabilities</b>	<b>Dec-19</b>	<b>Jan-20</b>	<b>Feb-20</b>	<b>Mar-20</b>	<b>Apr-20</b>	<b>May-20</b>	<b>Jun-20</b>	<b>Jul-20</b>	<b>Aug-20</b>	<b>Sep-20</b>	<b>Oct-20</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>13 Month Average</b>	<b>Notes</b>
254-00150, 254-00151	State Tax Reform Refund	\$ (3,694)	\$ (3,591)	\$ (3,488)	\$ (3,386)	\$ (3,283)	\$ (3,181)	\$ (3,078)	\$ (2,975)	\$ (2,873)	\$ (2,770)	\$ (2,668)	\$ (2,565)	\$ (2,462)	\$ (3,078)	(a)
254-00204	Federal Tax Reform - Federal Unprotected Excess ADITs	(523,555)	(509,012)	(494,468)	(479,925)	(465,382)	(450,839)	(436,296)	(421,752)	(407,209)	(392,666)	(378,123)	(363,580)	(349,036)	(436,296)	(a)
254-00207	Federal Tax Reform - Federal Protected Excess ADITs	(127,155)	(123,623)	(120,091)	(116,559)	(113,027)	(109,495)	(105,963)	(102,430)	(98,898)	(95,366)	(91,834)	(88,302)	(84,770)	(105,963)	(a)
254-00208	Federal Tax Reform - State Unprotected Excess ADITs	(10,286)	(10,000)	(9,714)	(9,429)	(9,143)	(8,857)	(8,572)	(8,286)	(8,000)	(7,714)	(7,429)	(7,143)	(6,857)	(8,572)	(a)
254-05110 - 254-05190; 254-00121 - 254-00134	Asset Retirement Obligations Regulatory Liability (e)	(703,781)	(695,455)	(687,128)	(678,802)	(670,475)	(662,148)	(653,822)	(645,495)	(637,169)	(628,842)	(620,516)	(612,189)	(603,862)	(653,822)	(b)

<b>FERC-SUB</b>	<b>Amortization Expenses</b>	<b>Jan-20</b>	<b>Feb-20</b>	<b>Mar-20</b>	<b>Apr-20</b>	<b>May-20</b>	<b>Jun-20</b>	<b>Jul-20</b>	<b>Aug-20</b>	<b>Sep-20</b>	<b>Oct-20</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>Total</b>	<b>Notes</b>
407-4xxxx (f)	State Tax Reform Refund	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (1,231)	(c)
411-10111	Federal Tax Reform - Federal Unprotected Excess ADITs	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(174,518)	(d)
411-10111	Federal Tax Reform - Federal Protected Excess ADITs	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(42,385)	(d)
411-10161	Federal Tax Reform - State Unprotected Excess ADITs	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(3,429)	(d)

**Notes:**

- (a) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 5 - Included in Line 32, "Tax Reform Regulatory Liability"
- (b) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 5 - Line 39, "ARO Regulatory Liability (254)"
- (c) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 6 - Line 27, "Amortization of State Tax Reform Refund"
- (d) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 6 - Included in Line 36, "Deferred Income Taxes"
- (e) These amounts include the debit balance in FERC account 254 related to ARO recovery and the ARO Regulatory Liability for Nuclear Decommissioning which is excluded from retail rate base.
- (f) Account has not been set up yet; proposed amortization will begin January 2020.

**GEORGIA POWER COMPANY**  
**REGULATORY LIABILITIES IN RATE BASE**  
**FOR THE FORECASTED PERIOD ENDING DECEMBER 31, 2021**  
**(AMOUNTS IN THOUSANDS)**

		<b>Dec-20</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>	<b>Jul-21</b>	<b>Aug-21</b>	<b>Sep-21</b>	<b>Oct-21</b>	<b>Nov-21</b>	<b>Dec-21</b>	<b>12 Month Average</b>	<b>Notes</b>
<b>FERC-SUB</b>	<b>Regulatory Liabilities</b>															
254-00150, 254-00151	State Tax Reform Refund	\$ (2,462)	\$ (2,360)	\$ (2,257)	\$ (2,155)	\$ (2,052)	\$ (1,949)	\$ (1,847)	\$ (1,744)	\$ (1,642)	\$ (1,539)	\$ (1,436)	\$ (1,334)	\$ (1,231)	\$ (1,347)	(a)
254-00204	Federal Tax Reform - Federal Unprotected Excess ADITs	(349,036)	(334,493)	(319,950)	(305,407)	(290,864)	(276,320)	(261,777)	(247,234)	(232,691)	(218,148)	(203,604)	(189,061)	(174,518)	(261,777)	(a)
254-00207	Federal Tax Reform - Federal Protected Excess ADITs	(84,770)	(81,238)	(77,706)	(74,174)	(70,642)	(67,109)	(63,577)	(60,045)	(56,513)	(52,981)	(49,449)	(45,917)	(42,385)	(63,577)	(a)
254-00208	Federal Tax Reform - State Unprotected Excess ADITs	(6,857)	(6,572)	(6,286)	(6,000)	(5,714)	(5,429)	(5,143)	(4,857)	(4,572)	(4,286)	(4,000)	(3,714)	(3,429)	(5,143)	(a)
254-05110 - 254-05190; 254-00121 - 254-00134	Asset Retirement Obligations Regulatory Liability (e)	(603,862)	(596,646)	(589,430)	(582,214)	(574,998)	(567,782)	(560,565)	(553,349)	(546,133)	(538,917)	(531,701)	(524,485)	(517,268)	(560,565)	(b)

<b>FERC-SUB</b>	<b>Amortization Expenses</b>															
407-4xxxx (f)	State Tax Reform Refund	\$	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	\$ (1,231)	(c)
411-10111	Federal Tax Reform - Federal Unprotected Excess ADITs	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(174,518)	(d)
411-10111	Federal Tax Reform - Federal Protected Excess ADITs	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(42,385)	(d)
411-10161	Federal Tax Reform - State Unprotected Excess ADITs	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(3,429)	(d)

**Notes:**

- (a) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 7 - Included in Line 32, "Tax Reform Regulatory Liability"
- (b) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 7 - Line 39, "ARO Regulatory Liability (254)"
- (c) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 8 - Line 27, "Amortization of State Tax Reform Refund"
- (d) Reference Exhibit (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 8 - Included in Line 36, "Deferred Income Taxes"
- (e) These amounts include the debit balance in FERC account 254 related to ARO recovery and the ARO Regulatory Liability for Nuclear Decommissioning which is excluded from retail rate base.
- (f) Account has not been set up yet; proposed amortization will begin January 2020.

**GEORGIA POWER COMPANY**  
**REGULATORY LIABILITIES IN RATE BASE**  
**FOR THE FORECASTED PERIOD ENDING DECEMBER 31, 2022**  
**(AMOUNTS IN THOUSANDS)**

<b>FERC-SUB</b>	<b>Regulatory Liabilities</b>	<b>Dec-21</b>	<b>Jan-22</b>	<b>Feb-22</b>	<b>Mar-22</b>	<b>Apr-22</b>	<b>May-22</b>	<b>Jun-22</b>	<b>Jul-22</b>	<b>Aug-22</b>	<b>Sep-22</b>	<b>Oct-22</b>	<b>Nov-22</b>	<b>Dec-22</b>	<b>13 Month Average</b>	<b>Notes</b>
254-00150, 254-00151	State Tax Reform Refund	\$ (1,231)	\$ (1,129)	\$ (1,026)	\$ (923)	\$ (821)	\$ (718)	\$ (616)	\$ (513)	\$ (410)	\$ (308)	\$ (205)	\$ (103)	\$ -	\$ (616)	(a)
254-00204	Federal Tax Reform - Federal Unprotected Excess ADITs	(174,518)	(159,975)	(145,432)	(130,888)	(116,345)	(101,802)	(87,259)	(72,716)	(58,173)	(43,629)	(29,086)	(14,543)	0	(87,259)	(a)
254-00207	Federal Tax Reform - Federal Protected Excess ADITs	(42,385)	(38,853)	(35,321)	(31,789)	(28,256)	(24,724)	(21,192)	(17,660)	(14,128)	(10,596)	(7,064)	(3,532)	0	(21,192)	(a)
254-00208	Federal Tax Reform - State Unprotected Excess ADITs	(3,429)	(3,143)	(2,857)	(2,572)	(2,286)	(2,000)	(1,714)	(1,429)	(1,143)	(857)	(572)	(286)	(0)	(1,714)	(a)
254-05110 - 254-05190; 254-00121 - 254-00134	Asset Retirement Obligations Regulatory Liability (e)	(517,268)	(506,615)	(495,961)	(485,307)	(474,653)	(463,999)	(453,346)	(442,692)	(432,038)	(421,384)	(410,731)	(400,077)	(389,423)	(453,346)	(b)

<b>FERC-SUB</b>	<b>Amortization Expenses</b>	<b>Jan-22</b>	<b>Feb-22</b>	<b>Mar-22</b>	<b>Apr-22</b>	<b>May-22</b>	<b>Jun-22</b>	<b>Jul-22</b>	<b>Aug-22</b>	<b>Sep-22</b>	<b>Oct-22</b>	<b>Nov-22</b>	<b>Dec-22</b>	<b>Total</b>	<b>Notes</b>
407-4xxxx (f)	State Tax Reform Refund	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (103)	\$ (1,231)	(c)
411-10111	Federal Tax Reform - Federal Unprotected Excess ADITs	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(14,543)	(174,518)	(d)
411-10111	Federal Tax Reform - Federal Protected Excess ADITs	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(3,532)	(42,385)	(d)
411-10161	Federal Tax Reform - State Unprotected Excess ADITs	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(286)	(3,429)	(d)

**Notes:**

- (a) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 9 - Included in Line 32, "Tax Reform Regulatory Liability"
- (b) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 9 - Line 39, "ARO Regulatory Liability (254)"
- (c) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 10 - Line 27, "Amortization of State Tax Reform Refund"
- (d) Reference Exhibit (DPP/SP/AMBR-1, Schedule 1 Total Company) Page 10 - Included in Line 36, "Deferred Income Taxes"
- (e) These amounts include the debit balance in FERC account 254 related to ARO recovery and the ARO Regulatory Liability for Nuclear Decommissioning which is excluded from retail rate base.
- (f) Account has not been set up yet; proposed amortization will begin January 2020.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-106**

Question:

Does Georgia Power Company have excess accumulated deferred income taxes (EADIT) at 12/31/2017, 12/31/2018, or 6/30/2019? If not, explain fully why not. If so, identify the amounts of EADIT at each date by component.

Response:

Yes. Please see Attachment STF-L&A-1-106.

Contact: Richard Dodd

(Amounts in Thousands)

[illegible]

## Footnotes:

(a) Excess ADITs associated with the over/under tariffs were moved to the corresponding over/under-recovery balances.

(b) Excess ADITS related to the basis difference for Vogtle 3&4 CWIP were moved to a regulatory asset account 182-30204 to be addressed when Vogtle Units 3&4 are placed in service and included in base rates.

(c) Amount recorded in Account 254-00204 for unprotected excess ADT's regulatory liability balance related to the change in federal income tax rates as of December 31, 2017 and December 31, 2018.

(e) Amount recorded in Account 254-00200 for unprotected excess RDTA regulatory liability balances related to the change in federal income tax rates as of December 31, 2017 and December 31, 2019.

(e) Amount recorded in Account 254-00208 for estimated unprotected excess ADIT's regulatory liability balance related to the temporary change in Georgia state income tax rates as of December 31, 2018.

(e) Amount recorded in Account 254-00207 for estimated unprotected excess ADITs as of December 31, 2018. Estimate subject to 2018 tax return actualization to be filed in 2019.

(g) Amount recorded in Accounts 254-00204, 254-00207, and 254-00208 for unprotected excess ADITs regulatory liability balance as of June 30, 2019. Estimate subject to change with 2018 tax return actualization and 2019 property budget lineup.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-107**

Question:

Has the Company amortized any EADIT in 2018? If not, explain fully why not. If so, identify, quantify and explain the 2018 and 2019 EADIT amortizations in detail, and show the amortization periods being use for each component of EADIT.

Response:

The Company began amortizing protected excess deferred taxes in 2018 and 2019 using the average rate assumption method over the remaining regulatory property lives as required by the IRS normalization rules. However, in accordance with the Commission Order related to Tax Cuts and Jobs Act in Docket No. 36989, the Company has re-deferred this amortization of excess protected ADITs to an unprotected regulatory liability to be addressed in this base rate case filing.

As presented in the filing, the Company proposes to amortize the unprotected excess ADITs for the benefit of customers over the three-year period ending December 31, 2022. In addition, the remaining protected excess ADITs related to tax depreciation will continue to be amortized using the average rate assumption method as required by the Internal Revenue Service normalization rules.

Please see the Company's response to STF-L&A-1-119 for additional details.

Contact: Richard Dodd

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-119**

Question:

Show in detail how the Company has quantified and reflected Tax Cuts and Jobs Act of 2017 savings by account in the forecasted test year, and in each forecasted calendar year, 2020-2022.

Response:

Pursuant to the Commission Order in Docket No. 36989 (the "Order"), Georgia Power calculated savings related to the 2017 Tax Cuts and Jobs Act ("TCJA") by remeasuring the Accumulated Deferred Income Taxes ("ADITS") balance at December 2017 to the new federal income tax rate of 21% effective January 2018, with the unprotected excess ADITs deferred for consideration in this base rate case. In addition, the Company deferred the excess ADITs and estimated savings related to state income taxes for 2019 based on the new state income tax rate of 5.75% effective January 2019, and also deferred the amortization of protected excess ADITs in 2018 and 2019 for consideration in this base rate case. Please see the Company's response to STF-L&A-1-106 for details of these items and the regulatory liability accounts to which they are recorded. The accounts are reflected in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company), line 32 "Tax Reform Regulatory Liability", pages 3, 5, 7, and 9 for the forecast test year and each forecasted year 2020-2022, respectively.

The Company is proposing to amortize these regulatory liabilities over the 3-year period ending December 2022 for the benefit of customers, as provided in the Company's response to STF-L&A-1-20. The amortization for the savings related to state income taxes for 2019 is reflected in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) line 27 "Amortization of State Tax Reform Refund", pages 4, 6, 8, and 10 for the forecasted test year and each forecasted year 2020-2022, respectively. The remaining amortization of the regulatory liabilities is reflected as reductions to Deferred Income Taxes in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) line 36, pages 4, 6, 8, and 10 for the forecasted test year and each forecasted year 2020-2022, respectively.

In addition to amortization of the deferred savings described above, customers will also receive the benefit of the savings through the amortization of protected excess ADITs in 2020 through 2022. For federal protected excess ADITs, the amortization is required to follow the average rate assumption method under the Internal Revenue Service normalization rules. The amortization is approximately \$65 million annually and reflected as a reduction to Federal and State Income Taxes in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) line 36, pages 4, 6, 8, and 10



**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

for the forecasted test year and each forecasted year 2020-2022, respectively. The protected excess ADIT balances are identified in the Company's response to STF-L&A-1-106 and included in Exhibit\_\_(DPP/SPA/MBR-1, Schedule 1 Total Company) line items 40 and 41 under "Accumulated Deferred Income Taxes", pages 3, 5, 7, and 9 for the forecasted test year and each forecasted year 2020-2022, respectively.

The Company's revenue requirements for the test period and calendar years 2020 through 2022 also reflect the lower federal and state income tax rates in these income tax calculations, resulting in significant savings through lower income tax requirements for customers.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-11**

**STF-L&A-11-9**

Question:

Regulatory liabilities. Refer to the response to STF-L&A-1-20.

- a. Show in detail each component of the federal unprotected EADIT that comprises the \$525.555 million amount.
- b. Show in detail each component of the federal protected EADIT that comprises the \$104.855 million amount.
- c. Why is the amount of the federal protected EADIT increasing from the July 2019 amount of \$104.855 in subsequent months?
- d. Over what period is the federal unprotected EADIT being amortized?
- e. How was the period identified in response to part d determined? Explain fully and include all related analysis.
- f. Does the Company agree that determining the amortization period for the federal unprotected EADIT is up to the discretion of the Commission? If not, explain fully why not.
- g. Has the Company recorded an amortization of protected federal EADIT in 2018 or 2019? If not, explain fully why not. If so, show the amounts of federal protected EADIT amortization by month for each month of 2018 and 2019.
- h. Does the Company agree that the Average Rate Assumption Method (ARAM) must be used for the properly classified federal protected EADIT? If not, explain fully why not.
- i. What software does the Company use to compute the ARAM?
- j. Identify and provide the Company's ARAM-based amounts of protected federal EADIT for 2018 and 2019, and as projected for each year, 2020, 2021 and 2022. Include supporting workpapers and PowerTax reports.
- k. Show in detail each component of the state unprotected EADIT amount of \$10.286 million.
- l. Over what period is the state unprotected EADIT being amortized?
- m. How was the period identified in response to part l determined? Explain fully and include all related analysis.

Response:

- a. Please see Attachment STF-L&A-11-9a.
- b. The Company amortized protected excess deferred taxes in 2018 and 2019 using the average rate assumption method (ARAM) over the remaining regulatory property lives as required by the IRS normalization rules. However, in accordance with the Commission Order on Tax Cuts and Jobs Act in Docket No. 36989, the Company re-deferred this amortization of excess protected ADITs to an unprotected regulatory liability to be addressed in this base rate case filing.

The \$104.855 million represents the protected EADIT that was amortized from January 2018 through July 2019 and subsequently re-deferred to an unprotected regulatory liability account. Please see Attachment STF-L&A-11-9b for the 2018 & 2019 Protected EADIT amortization by month through July 2019. Please see Attachment STF-L&A-11-9c for the supporting workpapers and PowerTax reports used to generate the 2018 and 2019 Protected EADIT amortization amounts.

- c. The balance will continue to increase as the monthly protected EADIT amortization is re-deferred through December 2019.
- d. As presented in the filing, the Company proposes to amortize the federal unprotected excess ADITs for the benefit of customers over the three-year period ending December 31, 2022.
- e. The Company proposes to amortize the unprotected EADIT over three years to match the three-year rate case period in this filing.
- f. Yes, the Company agrees that determining the amortization period for the federal unprotected EADIT is up to the discretion of the Commission. As stated in the response to part 'e', the Company has proposed an amortization period that is beneficial to customers over the same 3-year period in the filing as the proposed amortization periods for many of the regulatory assets.
- g. Please see the Company's response to part 'b' above.
- h. Yes, the Company agrees that ARAM is required by the IRS Normalization rules to "protect" a regulated public utility's ADIT and Excess Tax Reserve that are attributable to different: (i) depreciation methods, including the time and manner in which salvage value is taken into account, and (ii) depreciation useful lives. Accordingly, the Company considers EADIT for accelerated depreciation in accounts 281 and 282 to be properly classified as protected.
- i. The Company uses the PowerTax module of the PowerPlan software application. "Protected" ADIT balances in Accounts 281 and 282, and related amortization of "protected" excess deferred income taxes are generated in the PowerTax system, which

maintains vintage records of all protected property in service and ADIT balances which have been provided from enacted tax rates over time, and subsequently turned around at the ARAM.

- j. Please see Attachment STF-L&A-11-9c.
- k. Please see Attachment STF-L&A-11-9d.
- l. The Company has proposed to amortize the state excess ADITs over the three-year period ending December 21, 2022.
- m. Please see the Company's response to part 'e' above.

(Amounts in Thousands)

**Total Excess ADITs**  
**July 31, 2019**

**UNPROTECTED**

**Account 190**

Accrual for Uncollectibles	\$	(345)
Affirmative Adjustments		1,432
Capitalized PPA SPC		(2,587)
Income Tax Deferred - Electric		(19,781)
Injuries & Damages		(1,791)
Other Deferred Costs		(84,346)
Retail Rate Refund PSC		(5,503)
Tax Credit Carry Forward		12,787

**Account 282**

Basis Differences	\$	247,765
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**Account 283**

Additional Pension Deduction	\$	150,580
Customer Advances For Construction		(1,028)
Deferred Revenues		(190)
Emission Allowances		(126)
Levelized Purchase Power		2,204
Nuclear Outage		4,471
Premium on Reacquired Debt		17,816
Reg Asset - Branch		14,664
Reg Asset - Env Decertification		6,776
Reg Asset - Mitchell		1,600
Reg Asset - Obsolete Inventory		4,257
Storm Damage		46,635
Deferred Healthcare Costs		(4,171)

**Tax Reform Impact on ADITS (Unprotected)**

Gross-up for future revenue reduction (FERC 190)	\$	391,119
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**TOTAL Unprotected Excess ADITs** **\$ 523,555 (a)**

Footnotes:

(a) Amounts recorded in Accounts 254-00204 for unprotected excess ADITs regulatory liability balance as of July 31, 2019.

**GEORGIA POWER COMPANY**  
**PROTECTED EXCESS DEFERRED INCOME TAX AMORTIZATION**  
 (AMOUNTS IN THOUSANDS)

	<u>Jan-18</u>	<u>Feb-18</u>	<u>Mar-18</u>	<u>Apr-18</u>	<u>May-18</u>	<u>Jun-18</u>	<u>Jul-18</u>	<u>Aug-18</u>	<u>Sep-18</u>	<u>Oct-18</u>	<u>Nov-18</u>	<u>Dec-18</u>	<u>Total</u>	<u>Notes:</u>
<b>Protected EADIT Amortization</b>														
Amortization of Protected EADIT	\$ -	\$ (7,795)	\$ (3,898)	\$ (3,898)	\$ (3,898)	\$ (3,766)	\$ (3,876)	\$ (3,876)	\$ (3,876)	\$ (3,876)	\$ (3,876)	\$ (13,062)	\$ (55,696)	(a)
Grossup for Revenue Requirements	-	(2,664)	(1,332)	(1,332)	(1,332)	(1,287)	(1,325)	(1,325)	(1,325)	(1,325)	(1,325)	(4,464)	(19,035)	(b)
Re-deferred Protected EADIT to Unprotected Regulatory Liability	-	10,460	5,230	5,230	5,230	5,054	5,200	5,200	5,200	5,200	5,200	17,526	74,731	(c)
Cost of Service Impact	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
<b>Protected EADIT Amortization</b>														
Amortization of Protected EADIT	\$ (3,327)	\$ (3,327)	\$ (3,327)	\$ (2,878)	\$ (3,296)	\$ (3,119)	\$ (3,362)						\$ (22,636)	(a)
Grossup for Revenue Requirements	(1,137)	(1,137)	(1,137)	(767)	(1,116)	(1,056)	(1,138)						(7,488)	(b)
Re-deferred Protected EADIT to Unprotected Regulatory Liability	4,464	4,464	4,464	3,645	4,413	4,175	4,500						30,124	(c)
Cost of Service Impact	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -						\$ -	

Notes:

- (a) Based on Power Tax data using the average rate assumption method.  
 (b) Amortization grossed up for federal and state income taxes.  
 (c) Re-deferred to account 25400207

GEORGIA POWER COMPANY  
PROTECTED EXCESS DEFERRED CALCULATION  
(AMOUNT IN THOUSANDS)

	(A)* CURRENT TIMING DIFFERENCE DEPRECIATION	(B)* GAIN/(LOSS)	(C) STATUTORY RATES	(D) DEFERRED TAX AT STATUTORY RATE	(E)* DEFERRED TAX AT ARAM	(F) EXCESS DEFERRED DIFFERENCE	(G) EXCESS DEFERRED GROSSED UP
<b>2018</b>							
Federal	E1 \$272,395	E1 \$21,094	21%	\$61,633	E1 \$2,886	(\$58,746)	
Federal Offset	E2 \$370,477	E2 \$40,612	-1.1887%	(\$4,887)	E2 (\$2,092)	\$2,794	
Adjustments**						\$257	
TOTAL	\$642,871	\$61,706		\$56,746	\$794	(\$55,695)	(\$74,731)
<b>2019</b>							
Federal	E3 (\$388,016)	E3 \$184,263	21%	(\$42,788)	E3 (\$115,622)	(\$72,834)	
Federal Offset	E4 (\$65,981)	E4 \$206,022	-1.1887%	(\$1,665)	E4 \$1,484	\$3,149	
Adjustments**						\$30,390	
TOTAL	(\$453,997)	\$390,285		(\$44,453)	(\$114,138)	(\$39,295)	(\$52,424)
<b>2020</b>							
Federal	E5 (\$91,108)	E5 \$143,781	21%	\$11,061	E5 (\$36,313)	(\$47,375)	
Federal Offset	E6 \$329,932	E6 \$163,443	-1.1887%	(\$5,865)	E6 (\$3,876)	\$1,988	
Adjustments**						(\$2,736)	
TOTAL	\$238,824	\$307,223		\$5,197	(\$40,190)	(\$48,122)	(\$64,417)
<b>2021</b>							
Federal	E7 \$169,208	E7 \$142,808	21%	\$65,523	E7 \$17,832	(\$47,691)	
Federal Offset	E8 \$536,050	E8 \$153,741	-1.1887%	(\$8,199)	E8 (\$5,995)	\$2,204	
Adjustments**						(\$2,746)	
TOTAL	\$705,258	\$296,548		\$57,324	\$11,837	(\$48,233)	(\$64,565)
<b>2022</b>							
Federal	E9 \$406,403	E9 \$137,485	21%	\$114,217	E9 \$63,793	(\$50,423)	
Federal Offset	E10 \$723,973	E10 \$153,138	-1.1887%	(\$10,426)	E10 (\$8,077)	\$2,349	
Adjustments**						(\$2,749)	
TOTAL	\$1,130,376	\$290,623		\$103,791	\$55,716	(\$50,824)	(\$68,033)

## Notes:

\*Balances listed for columns (A), (B), and (E) for the Federal and Federal Offset lines come directly from the PowerTax system reports (see additional pages included in this attachment).

(C) represents the statutory tax rates used in the Average Rate Assumption calculation per Power Tax.

(D)=(A+B)\*(C)

(F) is the difference between columns (D) and (E). This represents the difference between deferred taxes calculated at current tax rates (D) and the deferred taxes tracked at the historical rates (E) using the average rate assumption method. Column (F) represents the total protected EDIT for the year.

(G) Represents the grossed up balance in the regulatory liability account.

\*\*Adjustments are made for certain items that are tracked outside PowerTax. These items primarily include wholesale protected excess ADITS and protected excess on retired units that are being amortized in regulatory assets. The adjustment in 2019 re-defers approximately \$29 million for the excess ADIT amortization associated with the retirements for tax purposes for Plants Hammond, McIntosh, Estatoth, Langdale and Riverview. The protected excess associated with these retired units will be amortized over same period as regulatory asset containing the remaining net book value of retired units beginning in 2020.

The 2018 protected excess deferred amortization above is based on preliminary estimates and will change with the actualization of the 2018 federal tax return filed in the third quarter of 2019. 2019 through 2022 are also estimates based on the rate case property budget.

Grouped By: Total Tax Classes

Jurisdiction: Federal Tax Year: 2018	Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
Jurisdiction: Federal										
Federal Cor	\$128,500,210.01	\$155,108,131.36	(\$26,985,044.10)	\$32,572,707.59	(\$36,506,126.80)	\$46,282,120.05	\$0.10	\$13,716,365.26	\$9,521,082.79	\$6,952.79
Federal Life Fed	(\$13,702,247.88)	(\$1,511,762.48)	(\$2,877,472.05)	(\$317,470.12)	(\$4,612,893.61)	(\$528,421.62)	\$21,671.14	\$53,670.64	\$1,757,092.69	\$264,622.15
Federal Life FT Fed	(\$76,142.23)	\$31,643.83	(\$15,989.87)	\$6,645.20	\$0.00	\$0.00	\$19,319.59	\$1,668.29	\$3,329.72	\$8,313.49
Federal Method Fed	(\$760,435.80)	(\$109,754.09)	(\$159,691.52)	(\$23,048.36)	(\$722,771.37)	(\$40,128.00)	\$2,526.02	\$8,976.28	\$565,605.87	\$26,055.92
Federal Method Life Fed	\$415,433,671.55	\$132,424,575.24)	\$87,241,071.03	(\$27,809,160.80)	\$47,272,215.45	(\$48,257,913.51)	\$4,397,646.81	\$1,694,501.69	\$44,366,502.39	\$22,143,254.41
Depreciation Difference	\$272,394,635.63	\$21,093,683.38	\$57,202,873.48	\$4,429,673.51	\$5,430,423.68	(\$2,544,343.09)	\$4,441,163.66	\$15,475,182.16	\$56,213,613.46	\$22,449,198.76
Total Tax Classes	\$272,394,635.63	\$21,093,683.38	\$57,202,873.48	\$4,429,673.51	\$5,430,423.68	(\$2,544,343.09)	\$4,441,163.66	\$15,475,182.16	\$56,213,613.46	\$22,449,198.76
Jurisdiction Total:	\$272,394,635.63	\$21,093,683.38	\$57,202,873.48	\$4,429,673.51	\$5,430,423.68	(\$2,544,343.09)	\$4,441,163.66	\$15,475,182.16	\$56,213,613.46	\$22,449,198.76

SUM A = 2,886,081 D1



Grouped By: Total Tax Classes

Jurisdiction: Fed Georgia Of		Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
Tax Year: 2018		Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Fed Georgia Offset</b>											
Fed Ga Offset Cor		\$128,500,210.01)	\$155,108,131.36	\$1,527,353.50	(\$1,843,615.25)	\$2,066,633.00	(\$2,620,257.36)	\$539,279.64	\$393.63	\$0.13	\$777,035.74
Fed Ga Offset Life FT State		(\$936,857.43)	(\$22,888.68)	(\$196,740.06)	(\$4,806.62)	\$0.00	\$0.00	\$200,069.78	\$13,120.12	\$3,329.72	\$8,313.50
Fed Ga Offset Life State		(\$12,815,480.55)	(\$1,457,243.02)	\$152,324.80	\$17,320.79	\$245,747.95	\$29,384.57	\$94,850.28	\$15,101.46	\$1,427.13	\$3,037.68
Fed Ga Offset Method FT Stati		(\$2,054.42)	(\$1.80)	(\$431.43)	(\$0.38)	\$0.00	\$0.00	\$431.43	\$0.38	\$0.00	\$0.00
Fed Ga Offset Method Life FT		(\$909,961.35)	(\$31,814.88)	(\$191,091.88)	(\$6,681.12)	\$0.00	\$0.00	\$191,091.88	\$6,683.67	\$0.00	\$2.54
Fed Ga Offset Method Life Sta		\$514,395,701.19	\$112,874,385.88)	(\$6,114,107.30)	\$1,341,624.95	(\$4,351,436.98)	\$2,494,178.41	\$2,011,736.53	\$1,247,116.70	\$249,066.20	\$94,563.24
Fed Ga Offset Method State		(\$754,573.73)	(\$109,752.29)	\$8,968.86	\$1,304.52	\$41,035.32	\$2,273.65	\$32,209.85	\$1,477.24	\$143.39	\$508.11
<b>Depreciation Difference</b>		<b>\$370,476,563.70</b>	<b>\$40,612,044.81</b>	<b>\$4,813,723.51</b>	<b>(\$494,853.12)</b>	<b>(\$1,998,020.70)</b>	<b>(\$94,420.74)</b>	<b>\$3,069,669.38</b>	<b>\$1,283,893.19</b>	<b>\$253,966.57</b>	<b>\$883,460.81</b>
<b>Total Tax Classes</b>		<b>\$370,476,563.70</b>	<b>\$40,612,044.81</b>	<b>(\$4,813,723.51)</b>	<b>(\$494,853.12)</b>	<b>(\$1,998,020.70)</b>	<b>(\$94,420.74)</b>	<b>\$3,069,669.38</b>	<b>\$1,283,893.19</b>	<b>\$253,966.57</b>	<b>\$883,460.81</b>
<b>Jurisdiction Total:</b>		<b>\$370,476,563.70</b>	<b>\$40,612,044.81</b>	<b>(\$4,813,723.51)</b>	<b>(\$494,853.12)</b>	<b>(\$1,998,020.70)</b>	<b>(\$94,420.74)</b>	<b>\$3,069,669.38</b>	<b>\$1,283,893.19</b>	<b>\$253,966.57</b>	<b>\$883,460.81</b>
<b>Company Total:</b>		<b>\$642,871,199.33</b>	<b>\$61,705,728.19</b>	<b>\$52,389,149.97</b>	<b>\$3,934,820.39</b>	<b>\$3,432,402.98</b>	<b>(\$2,638,763.83)</b>	<b>\$7,510,833.04</b>	<b>\$16,759,075.35</b>	<b>\$56,467,580.03</b>	<b>\$23,332,659.57</b>

SUM A = (2,092,441.44) D1

Grouped By: Total Tax Classes

Jurisdiction: Federal Tax Year: 2019	Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Federal</b>										
Federal Cor	\$227,094,763.97)	\$118,723,741.99	(\$47,689,900.43)	\$24,931,985.82	(\$49,799,811.25)	\$27,781,529.86	\$0.16	\$2,849,544.18	\$2,109,910.97	\$0.14
Federal Life Fed	(\$12,471,990.70)	\$65,071.58	(\$2,619,118.05)	\$13,665.03	(\$4,142,995.75)	\$21,323.42	\$31,390.30	\$19,308.79	\$1,555,268.01	\$11,650.40
Federal Life FT Fed	(\$21,151.22)	\$20,111.75	(\$4,441.76)	\$4,223.47	\$0.00	\$0.00	\$8,094.08	\$0.00	\$3,652.33	\$4,223.47
Federal Method Fed	(\$607,350.34)	(\$25,907.03)	(\$127,543.57)	(\$5,440.48)	(\$680,882.68)	(\$14,339.69)	\$40,555.76	\$4,316.67	\$593,894.86	\$13,215.89
Federal Method Life Fed	\$147,820,552.50)	\$65,480,316.58	(\$31,042,316.03)	\$13,750,866.48	\$108,537,815.00)	\$19,751,315.74	\$3,408,964.54	\$6,586,807.04	\$80,904,463.52	\$586,357.78
<b>Depreciation Difference</b>	<b>\$388,015,808.73)</b>	<b>\$184,263,334.87</b>	<b>(\$81,483,319.83)</b>	<b>\$38,695,300.32</b>	<b>\$163,161,504.68)</b>	<b>\$47,539,829.33</b>	<b>\$3,489,004.84</b>	<b>\$9,459,976.68</b>	<b>\$85,167,189.69</b>	<b>\$615,447.68</b>
<b>Total Tax Classes</b>	<b>\$388,015,808.73)</b>	<b>\$184,263,334.87</b>	<b>(\$81,483,319.83)</b>	<b>\$38,695,300.32</b>	<b>\$163,161,504.68)</b>	<b>\$47,539,829.33</b>	<b>\$3,489,004.84</b>	<b>\$9,459,976.68</b>	<b>\$85,167,189.69</b>	<b>\$615,447.68</b>
<b>Jurisdiction Total:</b>	<b>\$388,015,808.73)</b>	<b>\$184,263,334.87</b>	<b>(\$81,483,319.83)</b>	<b>\$38,695,300.32</b>	<b>\$163,161,504.68)</b>	<b>\$47,539,829.33</b>	<b>\$3,489,004.84</b>	<b>\$9,459,976.68</b>	<b>\$85,167,189.69</b>	<b>\$615,447.68</b>

SUM A = (115,621,675.35) D1

Grouped By: Total Tax Classes

Jurisdiction: Fed Georgia Of		Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
Tax Year: 2019		Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Fed Georgia Offset</b>											
Fed Ga Offset Cor	\$227,094,763.97)		\$118,723,741.99	\$2,699,248.36	(\$1,411,150.40)	\$2,818,669.22	(\$1,572,433.69)	\$119,421.39	\$0.49	\$0.53	\$161,283.79
Fed Ga Offset Life FT State	(\$761,790.76)		(\$8,233.77)	(\$159,976.06)	(\$1,729.09)	\$0.00	\$0.00	\$163,387.89	\$5,952.56	\$3,411.83	\$4,223.47
Fed Ga Offset Life State	(\$11,722,513.77)		\$94,420.56	\$139,333.80	(\$1,122.28)	\$196,026.97	(\$1,829.04)	\$83,872.28	\$401.86	\$27,179.10	\$1,108.62
Fed Ga Offset Method FT Stati	(\$2,101.94)		(\$0.02)	(\$441.41)	(\$0.00)	\$0.00	\$0.00	\$441.41	\$0.00	\$0.00	\$0.00
Fed Ga Offset Method Life FT	(\$832,690.46)		(\$12,357.93)	(\$174,865.00)	(\$2,595.17)	\$0.00	\$0.00	\$174,865.00	\$2,667.15	\$0.00	\$71.98
Fed Ga Offset Method Life Sta	\$175,036,122.00	\$87,249,990.58		(\$2,080,479.35)	(\$1,037,053.39)	\$1,405,620.19	(\$1,401,410.40)	\$3,717,692.48	\$28,983.20	\$231,592.95	\$393,340.21
Fed Ga Offset Method State	(\$602,989.89)		(\$25,907.01)	\$7,167.14	\$307.93	\$38,688.45	\$819.53	\$33,816.83	\$756.00	\$2,295.52	\$244.39
<b>Depreciation Difference</b>	<b>(\$65,980,728.79)</b>		<b>\$206,021,654.40</b>	<b>\$429,987.49</b>	<b>(\$2,453,342.40)</b>	<b>\$4,459,004.83</b>	<b>(\$2,974,853.60)</b>	<b>\$4,293,497.27</b>	<b>\$38,761.26</b>	<b>\$264,479.93</b>	<b>\$560,272.46</b>
<b>Total Tax Classes</b>	<b>(\$65,980,728.79)</b>		<b>\$206,021,654.40</b>	<b>\$429,987.49</b>	<b>(\$2,453,342.40)</b>	<b>\$4,459,004.83</b>	<b>(\$2,974,853.60)</b>	<b>\$4,293,497.27</b>	<b>\$38,761.26</b>	<b>\$264,479.93</b>	<b>\$560,272.46</b>
<b>Jurisdiction Total:</b>	<b>(\$65,980,728.79)</b>		<b>\$206,021,654.40</b>	<b>\$429,987.49</b>	<b>(\$2,453,342.40)</b>	<b>\$4,459,004.83</b>	<b>(\$2,974,853.60)</b>	<b>\$4,293,497.27</b>	<b>\$38,761.26</b>	<b>\$264,479.93</b>	<b>\$560,272.46</b>
<b>Company Total:</b>	<b>\$453,996,537.52)</b>		<b>\$390,284,989.27</b>	<b>(\$81,053,332.34)</b>	<b>\$36,241,957.92</b>	<b>\$158,702,499.85)</b>	<b>\$44,564,975.73</b>	<b>\$7,782,502.12</b>	<b>\$9,498,737.94</b>	<b>\$85,431,669.62</b>	<b>\$1,175,720.14</b>

SUM A = 1,484,151.23 D1

Grouped By: Total Tax Classes

Jurisdiction: Federal Tax Year: 2020	Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Federal</b>										
Federal Cor	\$134,392,028.02	\$109,360,681.02	\$28,222,325.88	\$22,965,743.01	(\$32,333,925.58)	\$28,094,962.86	\$11,384.59	\$5,129,219.86	\$4,122,984.29	\$0.02
Federal Life Fed	(\$16,314,207.76)	\$8,968.72	(\$3,425,983.63)	\$1,883.43	(\$5,378,559.39)	\$2,684.68	\$15,322.63	\$4,344.08	\$1,967,898.40	\$3,542.83
Federal Life FT Fed	(\$54,723.70)	\$5,231.45	(\$11,491.98)	\$1,098.60	\$0.00	\$0.00	\$14,186.96	\$0.00	\$2,694.99	\$1,098.60
Federal Method Fed	(\$996,585.70)	(\$18,022.69)	(\$209,283.00)	(\$3,784.76)	(\$817,679.54)	(\$9,242.72)	\$2,589.86	\$1,331.88	\$610,986.41	\$6,789.83
Federal Method Life Fed	\$60,649,599.47	\$34,423,882.21	\$12,736,415.89	\$7,229,015.26	(\$33,603,501.24)	\$7,731,939.77	\$1,955,071.62	\$634,165.47	\$48,294,988.75	\$131,240.96
<b>Depreciation Difference</b>	<b>(\$91,107,945.71)</b>	<b>\$143,780,740.71</b>	<b>(\$19,132,668.60)</b>	<b>\$30,193,955.55</b>	<b>(\$72,133,665.76)</b>	<b>\$35,820,344.60</b>	<b>\$1,998,555.67</b>	<b>\$5,769,061.29</b>	<b>\$54,999,552.83</b>	<b>\$142,672.24</b>
<b>Total Tax Classes</b>	<b>(\$91,107,945.71)</b>	<b>\$143,780,740.71</b>	<b>(\$19,132,668.60)</b>	<b>\$30,193,955.55</b>	<b>(\$72,133,665.76)</b>	<b>\$35,820,344.60</b>	<b>\$1,998,555.67</b>	<b>\$5,769,061.29</b>	<b>\$54,999,552.83</b>	<b>\$142,672.24</b>
<b>Jurisdiction Total:</b>	<b>(\$91,107,945.71)</b>	<b>\$143,780,740.71</b>	<b>(\$19,132,668.60)</b>	<b>\$30,193,955.55</b>	<b>(\$72,133,665.76)</b>	<b>\$35,820,344.60</b>	<b>\$1,998,555.67</b>	<b>\$5,769,061.29</b>	<b>\$54,999,552.83</b>	<b>\$142,672.24</b>

SUM A = (36,313,321.16) D1

Grouped By: Total Tax Classes

Jurisdiction: Fed Georgia Of		Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
Tax Year: 2020		Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Fed Georgia Offset</b>											
Fed Ga Offset Cor		\$134,392,028.02	\$109,360,681.02	\$1,597,383.65	(\$1,299,861.05)	\$1,830,136.93	(\$1,590,249.23)	\$233,398.13	\$0.04	\$644.85	\$290,388.21
Fed Ga Offset Life FT State		(\$744,061.73)	(\$5,361.86)	(\$156,252.96)	(\$1,125.99)	\$0.00	\$0.00	\$158,947.95	\$2,224.60	\$2,694.99	\$1,098.60
Fed Ga Offset Life State		(\$15,622,249.31)	\$19,562.03	\$185,686.06	(\$232.51)	\$294,100.71	(\$379.97)	\$109,324.75	\$100.63	\$910.09	\$248.09
Fed Ga Offset Method FT Stati		(\$1,449.52)	(\$0.01)	(\$304.40)	(\$0.00)	\$0.00	\$0.00	\$304.40	\$0.00	\$0.00	\$0.00
Fed Ga Offset Method Life FT		(\$691,576.04)	(\$4,955.54)	(\$145,230.97)	(\$1,040.66)	\$0.00	\$0.00	\$145,230.97	\$1,108.92	\$0.00	\$68.25
Fed Ga Offset Method Life Sta		\$482,380,947.49	\$54,090,601.76	(\$5,733,579.94)	(\$642,920.89)	(\$3,698,582.85)	(\$758,267.03)	\$2,181,097.83	\$6,613.39	\$146,100.73	\$121,959.53
Fed Ga Offset Method State		(\$997,756.60)	(\$18,022.68)	\$11,859.33	\$214.22	\$46,527.05	\$527.21	\$34,814.36	\$388.36	\$146.65	\$75.37
<b>Depreciation Difference</b>		<b>\$329,931,826.27</b>	<b>\$163,442,504.72</b>	<b>\$4,240,439.24</b>	<b>(\$1,944,966.90)</b>	<b>(\$1,527,818.15)</b>	<b>A (\$2,348,369.03)</b>	<b>\$2,863,118.39</b>	<b>\$10,435.94</b>	<b>\$150,497.31</b>	<b>\$413,838.06</b>
<b>Total Tax Classes</b>		<b>\$329,931,826.27</b>	<b>\$163,442,504.72</b>	<b>(\$4,240,439.24)</b>	<b>(\$1,944,966.90)</b>	<b>(\$1,527,818.15)</b>	<b>(\$2,348,369.03)</b>	<b>\$2,863,118.39</b>	<b>\$10,435.94</b>	<b>\$150,497.31</b>	<b>\$413,838.06</b>
<b>Jurisdiction Total:</b>											
<b>Company Total:</b>		<b>\$238,823,880.56</b>	<b>\$307,223,245.43</b>	<b>(\$23,373,107.84)</b>	<b>\$28,248,988.65</b>	<b>(\$73,661,483.91)</b>	<b>\$33,471,975.57</b>	<b>\$4,861,674.06</b>	<b>\$5,779,497.23</b>	<b>\$55,150,050.14</b>	<b>\$556,510.30</b>

SUM A = (3,876,187.18) D1

Grouped By: Total Tax Classes

Jurisdiction: Federal Tax Year: 2021	Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Federal</b>										
Federal Cor	\$142,938,101.01	\$118,965,056.02	\$30,017,001.21	\$24,982,661.76	(\$34,523,720.94)	\$30,387,976.37	\$6,050.32	\$5,405,314.63	\$4,512,770.05	\$0.02
Federal Life Fed	(\$14,870,646.45)	(\$1,253.43)	(\$3,122,835.75)	(\$263.22)	(\$4,936,831.52)	(\$613.66)	\$16,068.62	\$522.51	\$1,830,064.39	\$872.94
Federal Life FT Fed	(\$55,645.92)	\$929.01	(\$11,685.64)	\$195.09	\$0.00	\$0.00	\$14,411.44	\$0.00	\$2,725.80	\$195.09
Federal Method Fed	(\$962,935.58)	(\$7,190.06)	(\$202,216.47)	(\$1,509.91)	(\$802,686.85)	(\$3,773.10)	\$2,585.82	\$428.17	\$603,056.20	\$2,691.36
Federal Method Life Fed	\$328,035,286.20	\$23,850,069.09	\$68,887,410.10	\$5,008,514.51	\$22,176,203.10	\$5,535,729.27	\$1,656,562.93	\$564,239.95	\$48,367,769.93	\$37,025.19
<b>Depreciation Difference</b>	<b>\$169,207,957.24</b>	<b>\$142,807,610.63</b>	<b>\$35,533,671.02</b>	<b>\$29,989,598.23</b>	<b>(\$18,087,036.21)</b>	<b>\$35,919,318.88</b>	<b>\$1,695,679.13</b>	<b>\$5,970,505.26</b>	<b>\$55,316,386.37</b>	<b>\$40,784.61</b>
<b>Total Tax Classes</b>	<b>\$169,207,957.24</b>	<b>\$142,807,610.63</b>	<b>\$35,533,671.02</b>	<b>\$29,989,598.23</b>	<b>(\$18,087,036.21)</b>	<b>\$35,919,318.88</b>	<b>\$1,695,679.13</b>	<b>\$5,970,505.26</b>	<b>\$55,316,386.37</b>	<b>\$40,784.61</b>
<b>Jurisdiction Total:</b>	<b>\$169,207,957.24</b>	<b>\$142,807,610.63</b>	<b>\$35,533,671.02</b>	<b>\$29,989,598.23</b>	<b>(\$18,087,036.21)</b>	<b>\$35,919,318.88</b>	<b>\$1,695,679.13</b>	<b>\$5,970,505.26</b>	<b>\$55,316,386.37</b>	<b>\$40,784.61</b>

SUM A = 17,832,282.67 D1

Grouped By: Total Tax Classes

Jurisdiction: Fed Georgia Of		Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
Tax Year: 2021		Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Fed Georgia Offset</b>											
Fed Ga Offset Cor		\$142,938,101.01	\$118,965,056.02	\$1,698,962.27	(\$1,414,018.66)	\$1,954,079.95	(\$1,720,061.27)	\$255,460.44	\$0.01	\$342.76	\$306,042.62
Fed Ga Offset Life FT State		(\$632,550.01)	(\$1,707.13)	(\$132,835.50)	(\$358.50)	\$0.00	\$0.00	\$135,561.30	\$553.59	\$2,725.80	\$195.09
Fed Ga Offset Life State		(\$14,291,106.94)	\$1,382.71	\$169,864.10	(\$16.43)	\$271,308.56	(\$21.62)	\$102,399.45	\$24.89	\$954.99	\$30.07
Fed Ga Offset Method FT Stati		(\$676.23)	(\$0.03)	(\$142.01)	(\$0.01)	\$0.00	\$0.00	\$142.01	\$0.01	\$0.00	\$0.00
Fed Ga Offset Method Life FT		(\$636,590.01)	(\$1,794.33)	(\$133,683.90)	(\$376.81)	\$0.00	\$0.00	\$133,683.90	\$447.19	\$0.00	\$70.38
Fed Ga Offset Method Life Sta		\$695,514,044.38	\$34,784,943.67	(\$8,266,879.93)	(\$413,453.84)	(\$6,104,547.99)	(\$441,738.22)	\$2,253,859.45	\$1,672.89	\$91,527.51	\$29,957.27
Fed Ga Offset Method State		(\$964,894.77)	(\$7,190.03)	\$11,468.74	\$85.46	\$45,695.54	\$215.11	\$34,373.18	\$153.87	\$146.38	\$24.22
<b>Depreciation Difference</b>		<b>\$536,050,125.41<sup>b1</sup></b>	<b>\$153,740,690.88<sup>b2</sup></b>	<b>(\$6,653,246.24)</b>	<b>(\$1,828,138.78)</b>	<b>(\$3,833,463.94)<sup>A</sup></b>	<b>(\$2,161,606.00)<sup>A</sup></b>	<b>\$2,915,479.74</b>	<b>\$2,852.44</b>	<b>\$95,697.45</b>	<b>\$336,319.66</b>
<b>Total Tax Classes</b>		<b>\$536,050,125.41</b>	<b>\$153,740,690.88</b>	<b>(\$6,653,246.24)</b>	<b>(\$1,828,138.78)</b>	<b>(\$3,833,463.94)</b>	<b>(\$2,161,606.00)</b>	<b>\$2,915,479.74</b>	<b>\$2,852.44</b>	<b>\$95,697.45</b>	<b>\$336,319.66</b>
<b>Jurisdiction Total:</b>		<b>\$536,050,125.41</b>	<b>\$153,740,690.88</b>	<b>(\$6,653,246.24)</b>	<b>(\$1,828,138.78)</b>	<b>(\$3,833,463.94)</b>	<b>(\$2,161,606.00)</b>	<b>\$2,915,479.74</b>	<b>\$2,852.44</b>	<b>\$95,697.45</b>	<b>\$336,319.66</b>
<b>Company Total:</b>		<b>\$705,258,082.65</b>	<b>\$296,548,301.51</b>	<b>\$28,880,424.78</b>	<b>\$28,161,459.45</b>	<b>(\$21,920,500.15)</b>	<b>\$33,757,712.88</b>	<b>\$4,611,158.88</b>	<b>\$5,973,357.70</b>	<b>\$55,412,083.81</b>	<b>\$377,104.27</b>

SUM A = (5,995,069.94) D1



Grouped By: Total Tax Classes

Jurisdiction: Federal Tax Year: 2022	Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Federal</b>										
Federal Cor	\$152,728,784.05)	\$104,668,416.97	(\$32,073,044.65)	\$21,980,367.56	(\$33,471,711.51)	\$22,972,600.80	\$6,602.18	\$992,233.50	\$1,405,269.03	\$0.27
Federal Life Fed	(\$10,085,661.49)	(\$1,652.68)	(\$2,117,988.91)	(\$347.06)	(\$3,325,736.19)	(\$686.60)	\$19,060.90	\$202.12	\$1,226,808.18	\$541.65
Federal Life FT Fed	(\$58,461.93)	\$437.35	(\$12,277.01)	\$91.84	\$0.00	\$0.00	\$16,274.61	\$0.00	\$3,997.61	\$91.84
Federal Method Fed	(\$954,550.83)	(\$5,789.47)	(\$200,455.67)	(\$1,215.79)	(\$799,286.82)	(\$3,050.25)	\$2,598.70	\$226.80	\$601,429.84	\$2,061.27
Federal Method Life Fed	\$570,230,661.25	\$32,823,715.54	\$119,748,438.86	\$6,892,980.26	\$71,005,335.67	\$7,415,663.12	\$1,544,095.15	\$550,351.81	\$50,287,198.34	\$27,668.95
<b>Depreciation Difference</b>	<b>\$406,403,202.95</b>	<b>\$137,485,127.71</b>	<b>\$85,344,672.62</b>	<b>\$28,871,876.82</b>	<b>\$33,408,601.16</b>	<b>\$30,384,527.06</b>	<b>\$1,588,631.53</b>	<b>\$1,543,014.23</b>	<b>\$53,524,703.00</b>	<b>\$30,363.98</b>
<b>Total Tax Classes</b>	<b>\$406,403,202.95</b>	<b>\$137,485,127.71</b>	<b>\$85,344,672.62</b>	<b>\$28,871,876.82</b>	<b>\$33,408,601.16</b>	<b>\$30,384,527.06</b>	<b>\$1,588,631.53</b>	<b>\$1,543,014.23</b>	<b>\$53,524,703.00</b>	<b>\$30,363.98</b>
<b>Jurisdiction Total:</b>	<b>\$406,403,202.95</b>	<b>\$137,485,127.71</b>	<b>\$85,344,672.62</b>	<b>\$28,871,876.82</b>	<b>\$33,408,601.16</b>	<b>\$30,384,527.06</b>	<b>\$1,588,631.53</b>	<b>\$1,543,014.23</b>	<b>\$53,524,703.00</b>	<b>\$30,363.98</b>

SUM A = 63,793,128.22 D1



Grouped By: Total Tax Classes

Jurisdiction: Fed Georgia Of		Current Difference		At Statutory Rate		Current Deferred Tax		Excess Debit		Excess Credit	
Tax Year: 2022		Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)	Depreciation	Gain/(Loss)
<b>Jurisdiction: Fed Georgia Offset</b>											
Fed Ga Offset Cor		\$152,728,784.05)	\$104,668,416.97	\$1,815,334.33	(\$1,244,088.80)	\$1,894,497.67	(\$1,300,248.36)	\$79,537.74	\$0.38	\$374.40	\$56,159.94
Fed Ga Offset Life FT State		(\$546,805.60)	(\$1,165.23)	(\$114,829.18)	(\$244.70)	\$0.00	\$0.00	\$118,825.08	\$336.54	\$3,995.90	\$91.84
Fed Ga Offset Life State		(\$9,594,690.52)	(\$50.10)	\$114,042.49	\$0.60	\$180,489.72	\$4.76	\$67,580.80	\$15.89	\$1,133.58	\$11.72
Fed Ga Offset Method FT Stati		(\$720.08)	\$0.00	(\$151.22)	\$0.00	\$0.00	\$0.00	\$151.22	\$0.00	\$0.01	\$0.00
Fed Ga Offset Method Life FT		(\$635,659.14)	(\$1,024.68)	(\$133,488.42)	(\$215.18)	\$0.00	\$0.00	\$133,488.42	\$275.66	\$0.00	\$60.48
Fed Ga Offset Method Life Sta		\$888,435,806.39	\$48,477,858.59	\$10,559,947.99	(\$576,207.83)	(\$8,298,455.28)	(\$598,992.74)	\$2,337,798.53	\$1,158.31	\$76,305.82	\$23,943.22
Fed Ga Offset Method State		(\$956,458.03)	(\$5,789.47)	\$11,368.46	\$68.81	\$45,501.92	\$173.78	\$34,280.62	\$117.80	\$147.16	\$12.84
<b>Depreciation Difference</b>		<b>\$723,972,688.97</b>	<b>\$153,138,246.08</b>	<b>(\$8,867,671.53)</b>	<b>(\$1,820,687.10)</b>	<b>(\$6,177,965.97)</b>	<b>(\$1,899,062.56)</b>	<b>\$2,771,662.41</b>	<b>\$1,904.60</b>	<b>\$81,956.85</b>	<b>\$80,280.05</b>
<b>Total Tax Classes</b>		<b>\$723,972,688.97</b>	<b>\$153,138,246.08</b>	<b>(\$8,867,671.53)</b>	<b>(\$1,820,687.10)</b>	<b>(\$6,177,965.97)</b>	<b>(\$1,899,062.56)</b>	<b>\$2,771,662.41</b>	<b>\$1,904.60</b>	<b>\$81,956.85</b>	<b>\$80,280.05</b>
<b>Jurisdiction Total:</b>		<b>\$723,972,688.97</b>	<b>\$153,138,246.08</b>	<b>(\$8,867,671.53)</b>	<b>(\$1,820,687.10)</b>	<b>(\$6,177,965.97)</b>	<b>(\$1,899,062.56)</b>	<b>\$2,771,662.41</b>	<b>\$1,904.60</b>	<b>\$81,956.85</b>	<b>\$80,280.05</b>
<b>Company Total:</b>		<b>1,130,375,891.92</b>	<b>\$290,623,373.79</b>	<b>\$76,477,001.09</b>	<b>\$27,051,189.72</b>	<b>\$27,230,635.19</b>	<b>\$28,485,464.50</b>	<b>\$4,360,293.95</b>	<b>\$1,544,918.82</b>	<b>\$53,606,659.85</b>	<b>\$110,644.04</b>

SUM A = (8,077,028.53) D1

**GEORGIA POWER COMPANY**  
**GEORGIA STATE EXCESS DEFERRED INCOME TAX AMORTIZATION**  
**FOR THE PERIOD ENDING DECEMBER 31, 2019**  
**(AMOUNTS IN THOUSANDS)**

<u>Forecasted Book/Tax</u> <u>Timing Reversal Change</u>	<u>Timing Reversal @</u> <u>5.66%**</u>	<u>Timing Reversal @</u> <u>5.44%**</u>	<u>Difference</u>	<u>Federal Offset @ 21%</u>	<u>State Excess Deferred</u> <u>Income Taxes</u>	<u>Grossed up for Revenue</u> <u>Requirement</u>
2019-2025* \$4,360,736	\$246,834	\$237,109	\$9,726	(\$2,042)	\$7,683	\$10,286

\* Note that the Georgia Income Tax Rate change will decrease from 6% to 5.75% from 2019 to 2025 and will increase back to 6% in 2026; therefore, the forecasted impact of the rate change recorded in the regulatory liability is based on previously recorded deferred taxes that are expected to turn or unwind in the 7-year period between January 2019 through December 2025. The Company expects that approximately \$4.4 billion of gross timing differences will reverse at the lower state income tax rate. No remeasurement was needed for state deferred income taxes that are expected to reverse or unwind after 2025.

\*\*Note, the 5.66% represents the adjusted 6% state income tax rate to account for the state for state deduction on the GA Income Tax Return. The 5.44% represents the adjusted 5.75% state income tax rate to account for the state for state deduction on the GA Income Tax Return.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-13**

**STF-L&A-13-6**

Question:

Excess ADIT. Refer to the response to STF-L&A-1-106.

- a. Is all EADIT related to claimed repairs deductions included in the amounts of unprotected account 282 EADIT for "Basis Differences"? If not, explain fully why not and identify any other EADIT for repairs deductions that is not reflected in those "Basis Differences" amounts.
- b. Is there any EADIT for claimed repairs deductions included in the Account 281 Accelerated Depreciation amounts? If so, identify how much EADIT for repairs deductions is included in each amount.
- c. Is there any EADIT for claimed repairs deductions included in the Account 282 Accelerated Depreciation amounts? If so, identify how much EADIT for repairs deductions is included in each amount.
- d. Does the Company agree that claimed repairs deductions are a basis difference and as such all related EADIT for repairs deductions should be classified as unprotected? If not, explain fully why not and provide the supporting analysis.
- e. Has the Company claimed accelerated tax depreciation on any amounts that have been claimed as repairs deductions? If so, identify the amounts and explain the basis for the accelerated tax depreciation.
- f. Was the 2018 and 2019 protected EADIT amortization calculated using the Average Rate Assumption Method? If not, explain fully why not.
- g. Was the 2018 and 2019 protected EADIT amortization calculated using PowerTax? If not, explain how it was calculated and provide the related Excel files. If yes, identify and provide the PowerTax reports showing the calculated ARAM based EADIT amortization for 2018 and 2019.
- h. Has the Company used PowerTax to compute protected EADIT amortization for 2020, 2021 and 2022 using the ARAM? If not, explain how the protected EADIT amortization was calculated for each of those plan years, and provide the related Excel files. If yes, identify and provide the PowerTax reports showing the calculated ARAM based EADIT amortization for 2020, 2021 and 2022.

Response:

- a. Yes, the Company treats claimed repairs deductions as basis differences for income tax purposes; therefore, all EADIT related to claimed repairs deductions is included in the "Basis Differences" line of the unprotected 282 account.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-13**

- b. No, there is no EADIT for claimed repairs deduction included in account 281 for Accelerated Depreciation.
- c. No, there is no EADIT for claimed repairs deduction included in account 282 for Accelerated Depreciation.
- d. Yes, the Company agrees that claimed repairs deductions are basis differences and should be classified as unprotected.
- e. No, the Company has not claimed any accelerated depreciation on amounts that have been claimed as repairs deductions.
- f. Yes, the 2018 and 2019 protected EADIT, which does not include any EADIT related to the claimed repairs deductions, was calculated using ARAM.  
Please see the Company's response to STF-L&A-11-9.
- g. Yes, please see the Company's response to STF-L&A-11-9.
- h. Yes, please see the Company's response to STF-L&A-11-9.

EXHIBIT\_\_(RS/RT-23)

THIS FILING IS

Item 1: ☒ An Initial (Original)  
SubmissionOR ☐ Resubmission No. \_\_\_\_

# FERC FINANCIAL REPORT

## FERC FORM No. 60: Annual Report of Centralized Service Companies

This report is mandatory under the Public Utility Holding Company Act of 2005, Section 1270, Section 309 of the Federal Power Act and 18 C.F.R. § 366.23. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)

Southern Company Services, Inc.

Year of Report

Dec 31, 2018

Page 307

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018
Southern Company Services, Inc.			
Schedule XXI - Methods of Allocation			

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator.

2. Include any other allocation methods used to allocate costs.

Schedule XXI - Methods of Allocation		
2018		
<p>The Company uses statistics based on previous year statistics; therefore, 2018 allocations were based on 2017 statistics. The statistics are updated if material changes occur throughout the year. Each participating company receives a pro rata share based upon its statistics defined by the following methods. Multiple versions of the bases are available to reflect the exclusion of specific companies if they do not participate in or benefit from particular projects or services.</p>		
	<u>Basis</u>	<u>Statistics</u>
	Affiliate	Shared equally among affiliates receiving the services.
	Capitalization	Book capitalization (defined as long-term debt, preferred stock, cumulative preferred stock and common shareholder equity) of each Customer Company.
	Carbon Emissions	Carbon Emissions are measured in Carbon Dioxide Equivalent Metric Tons for each generating company.
	Carbon Emissions Coal	Carbon Emissions are measured in Carbon Dioxide Equivalent Metric Tons for each generating company only from coal fired plants.
	Coal Capacity	Coal nameplate generating capacity (kilowatts) for each Customer Operating Company. Capacity operated by the Southern system but jointly owned by external parties is included. Capacity jointly owned by Southern Company affiliates is assigned on an ownership basis.
	Coal Generation	Generation (kilowatt-hours) from coal fuel sources of each Customer Operating Company. Generation from plants operated by the Southern system but jointly owned by external parties is included. Generation jointly owned by Southern Company affiliates is assigned on an ownership basis.
	Customer	Number of year-end customers of each Customer Operating Company (other than SEGCO and Southern Power).
	Employee	Number of year-end employees of each Customer Company.
	Employee (Generation)	Number of year-end employees of each Customer Company - Generation Employees Only.
	Financial	Average of the percentages of net fixed assets, operating expenses, and operating revenues of each Customer Company.
	Fossil Capacity	Fossil nameplate generating capacity (kilowatts) for each Customer Operating Company. Capacity operated by the Southern system but jointly owned by external parties is included. Capacity jointly owned by Southern Company affiliates is assigned on an ownership basis.
	Fossil Hydro Capacity	Fossil and hydro nameplate generating capacity (kilowatts) for each Customer Operating Company. Capacity operated by the Southern system but jointly owned by external parties is included. Capacity jointly owned by Southern Company affiliates is assigned on an ownership basis.
	Gas Burned	Volume of gas consumed (BTUs) by each Customer Operating Company.



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Schedule XXI - Methods of Allocation			

	Gas & Oil Capacity	Gas and Oil nameplate generating capacity (kilowatts) for each Customer Operating Company (Combustion Turbines, Cogeneration and Combined Cycle only). Capacity operated by the Southern system but jointly owned by external parties is included. Capacity jointly owned by Southern Company affiliates is assigned on an ownership basis.
	Insurance Premium	Insurance premiums of each Customer Company.
	Load	Annual operating area territorial load (defined as kilowatt-hours of total energy generated plus energy received minus energy delivered) plus other firm wholesale commitments of each Customer Operating Company other than Southern Electric Generating Company (SEGC).
	Network ID	Number of network identifications of each Customer Company.
	Sales For Resale	Megawatts of wholesale generation as reported in annual Form 10-K as Sales for Resale.
	System Air Availability Co	Twelve month flight hours by executives authorized to call out flights at each Customer Company. Utilization of system aircraft is billed based on a comparable undiscounted commercial fare for the itinerary flown. The remaining costs are billed using this allocation as an availability fee.
	Transmission Usage	Total megawatt-hour deliveries to territorial customers plus deliveries to Open Access Transmission Tariff (OATT) customers (including Network Services and Point-to-Point service) plus other transmission deliveries under contracts predating OATT.
If SCS is participating in an allocation basis, its cost share is distributed to all affiliates and non-affiliates as an indirect expense based on labor.		

## Allocation

Indicator	Allocation Basis	1	2	3	4	5	6	C	K	M	P	9	A	S	Business Units Using Allocation
A0	Load		X	X	X	X									Engineering, Environmental and Research, Information Technology, Marketing Services, Other - SWE, System Planning, SCG Exec and Corporate Support, Supply Chain Management
A1	Load		X	X	X	X					X				Environmental and Research, Executive and Corporate, Other - SWE, System Planning, SCG Exec and Corporate Support
AB	Gas Burned		X	X	X	X					X				Accounting, Finance, and Treasury, SCG Exec and Corporate Support
B3	Capitalization	X	X	X	X	X	X				X		X		Accounting, Finance, and Treasury
BD	Capitalization	X	X	X	X	X	X	X	X	X	X		X	X	Accounting, Finance, and Treasury
C6	Customer		X	X	X										Information Technology
CD	Coal Capacity		X	X	X	X									Engineering, Environmental and Research, SCG Exec and Corporate Support
CI	Capitalization	X	X	X	X	X	X	X	X		X				External Affairs
CK	Capitalization	X	X	X	X	X	X		X	X	X				Accounting, Finance, and Treasury
CM	Capitalization		X	X	X	X									Accounting, Finance, and Treasury, Human Resources

EXHIBIT\_\_(RS/RT-24)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-115**

Question:

Refer to the SCS 2018 FERC Form 60 at pages 402.1 through 402.4. Show in detail how each SCS allocation factor that was used during 2018 was calculated. Include related supporting calculations and Excel files.

Response:

Allocation factors are reviewed and updated annually as part of SCS' Affiliate Transaction Review process. Headcount, Network ID, and System Air statistics are updated quarterly. Other adjustments are made during the year if material events occur, such as acquisitions, divestitures, or plant retirements.

Please see Attachment STF-L&A-1-115 for the supporting calculations for each SCS allocation factor as of January 2018. Please note, due to the voluminous nature of the data provided, the attachment is being provided in electronic format only.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-116**

Question:

Has SCS updated any of its allocation factors for use in 2019? If not, explain fully why not. If so, identify and explain each allocation factor that SCS is using in 2019. Also provide the supporting calculations and Excel files showing the calculations for each allocation factor that SCS is using in 2019.

Response:

Allocation factors are reviewed and updated annually as part of SCS' Affiliate Transaction Review process. Headcount, Network ID, and System Air statistics are updated quarterly. Other adjustments are made during the year if material events occur, such as acquisitions, divestitures, or plant retirements.

Please see Attachment STF-L&A-1-116 for the supporting calculations for each SCS allocation factor as of January 2019. Please note, due to the voluminous nature of the data provided, the attachment is being provided in electronic format only.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-117**

Question:

Has there been any impact on SCS allocation factors in 2018 or 2019 related to the sale of Gulf Power Company to NextEra Energy? If not, explain fully why not. If so, identify, quantify and explain the impact on the SCS charges to Georgia Power in the forecasted test year, or in any forecasted calendar year, 2020-2022.

Response:

There were no SCS allocation changes in 2018 related to the sale of Gulf Power Company to NextEra Energy as the sale was not completed until January 1, 2019.

Southern Company and NextEra Energy entered into a Transition Service Agreement (TSA) detailing billing for future services to be continued during the interim period until the agreement is terminated. The SCS services to be provided to NextEra include charges related to its participation in the IIC pool, integrated transmission operations, and corporate services including retail billing, accounting, and IT support. NextEra will simply replace Gulf Power in the underlying allocation criteria for these services and will receive allocations and charges from SCS, in the same manner as Gulf Power previously did prior to the sale.

NextEra will not participate in SCS services such as insurance, human resources, treasury, banking, system air, legal counsel, financial planning, executive, external affairs or systems integration, and therefore, will be excluded from the allocation detail for these charges.

The total SCS budget was reduced to account for the expected impact of the Gulf divestiture, but the reduction was applied to the total SCS charges as a whole and the impact of these reductions were not isolated to those services which excluded NextEra.

Due to the multiple changes in allocation factors, including those not impacted by Gulf divestiture such as cost reduction efforts, updated allocation criteria, and changes in cost centers, as well as adjustments for the TSA and NextEra's discontinued services, an isolated impact of Gulf divestiture on SCS charges to the Company is not quantifiable.

Please see the Company's response to STF-L&A-1-116 for updated allocation factors in use for 2019.

EXHIBIT\_\_(RS/RT-25)

THIS FILING IS

Item 1: ☒ An Initial (Original)  
SubmissionOR ☐ Resubmission No. \_\_\_\_

# FERC FINANCIAL REPORT

## FERC FORM No. 60: Annual Report of Centralized Service Companies

This report is mandatory under the Public Utility Holding Company Act of 2005, Section 1270, Section 309 of the Federal Power Act and 18 C.F.R. § 366.23. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)

Southern Nuclear Operating Company, Inc.

Year of Report

Dec 31, 2018

Page 307



Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report  2018
Southern Nuclear Operating Company, Inc.			
Schedule XXI - Methods of Allocation			

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator.

2. Include any other allocation methods used to allocate costs.

Service Department or Function	Basis of Allocation
Southern Nuclear corporate departments benefitting all operating plants	The Company currently utilizes the Plant Basis method of allocating costs associated with the activities benefitting all operating plants. The Plant Basis method of allocation is the factor determined by dividing one plant by the total number of plants.

EXHIBIT\_\_(RS/RT-26)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-122**

Question:

Refer to the SNOC FERC Form 60 at page 402.1. Regarding the Plant Basis allocation method that SNOC uses:

- a. Does Georgia Power currently receive a 2/3rd's allocation (based on having 4 of the 6 operating nuclear units)? If not, identify, quantify and explain the Plant Basis allocation that was used in 2018.
- b. Identify the amounts of SNOC costs in 2018 by account that were allocated using the Plant Basis allocation.
- c. Explain whether, how and when that SNOC Plant Basis allocation factor will be updated when Vogtle Units 3 and 4 achieve commercial operation.
- d. As of what date is it expected that the SNOC Plant Basis allocation factor will be updated to 5/7ths Georgia Power and 2/7ths Alabama Power?
- e. As of what date is it expected that the SNOC Plant Basis allocation factor will be updated to 6/8ths Georgia Power and 2/8ths Alabama Power?
- f. Identify, quantify and explain the impact on forecasted calendar year 2021 and 2022 results from any changes in the SNOC Plant Basis allocation factor. Include supporting workpapers and Excel files showing the calculations.

Response:

- a. Yes.
- b. Please reference Southern Nuclear Operating Company 2018 FERC Form 60, *Schedule XVI – Analysis of Charges for Service*, columns (d) and (j) on pages 303 through 306 and 303a through 306a, respectively, for amounts of Southern Nuclear costs allocated to Georgia Power using the Plant Basis allocation.
- c. Upon Vogtle Unit 3 achieving commercial operation, Southern Nuclear will utilize the Unit Basis for the allocation of indirect charges, and Georgia Power will receive 5/7ths allocation for total charges. When Vogtle Unit 4 achieves commercial operation, Georgia Power will receive 6/8ths (or 3/4ths) allocation for total charges.
- d. The GPSC approved November 2021 and November 2022 as the target in-service dates for Vogtle Units 3 and 4, respectively, in its Order on the 17<sup>th</sup> Vogtle

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

- Construction Monitoring ("VCM") proceedings. As such, the expected date that the Southern Nuclear Plant Basis allocation factor will be updated to 5/7ths Georgia Power and 2/7ths Alabama Power is December 1, 2021.
- e. Please see the Company's response to part d. The expected date that the Southern Nuclear Plant Basis allocation factor will be updated to 3/4ths Georgia Power and 1/4ths Alabama Power is December 1, 2022.
- f. The below table details the impact on forecasted calendar year 2021 and 2022 results from changes in the SNC Plant Basis allocation factor. There is an additional cost allocated from SNC to GPC (GPC 100% dollars) of \$706 thousand in 2021 and \$9.4 million in 2022 due to the change in the Plant Basis allocation factor. Please refer to Attachment STF-L&A-1-122 for supporting workpapers and Excel files showing the calculation. While this is the expected impact to GPC when Vogtle Units 3 and 4 are placed in service, the cost allocated to Vogtle Units 3&4 are excluded from the Company's filing in this rate case.

<b>GPC Impact 100% Dollars</b>		
	<b>2021</b>	<b>2022</b>
Hatch 1&2	(\$705,549)	(\$9,353,657)
Vogtle 1&2	(705,549)	(9,353,657)
Vogtle 3	2,116,646	26,092,519
Vogtle 4	<u>0</u>	<u>1,968,453</u>
Total	\$705,549	\$9,353,657

### Total SNC Plant Basis Allocation

Periods	Monthly Allocation		Monthly Allocation	
	2021 Budget	Per Unit	2022 Budget	Per Unit
Jan 19 / Jan 19	\$ 17,510,713	\$ 2,918,452	\$ 18,130,392	\$ 2,590,056
Feb 19 / Feb 19	13,431,096	2,238,516	14,044,863	2,006,409
Mar 19 / Mar 19	16,798,263	2,799,711	17,566,463	2,509,495
Apr 19 / Apr 19	14,024,402	2,337,400	14,558,153	2,079,736
May 19 / May 19	14,751,136	2,458,523	15,496,670	2,213,810
Jun 19 / Jun 19	15,038,606	2,506,434	15,907,994	2,272,571
Jul 19 / Jul 19	13,106,173	2,184,362	13,661,950	1,951,707
Aug 19 / Aug 19	15,263,772	2,543,962	16,063,316	2,294,759
Sep 19 / Sep 19	12,222,629	2,037,105	12,915,893	1,845,128
Oct 19 / Oct 19	14,925,655	2,487,609	15,544,400	2,220,629
Nov 19 / Nov 19	14,344,019	2,390,670	14,978,368	2,139,767
Dec 19 / Dec 19	14,816,520	2,116,646	15,747,622	1,968,453
<b>Total</b>	<b>\$ 176,232,985</b>	<b>\$ 29,019,390</b>	<b>\$ 184,616,085</b>	<b>\$ 26,092,519</b>

### 2021 SNC Plant Basis Allocation To Each Site

Periods	Vogtle 1&2 2021		Vogtle 3 2021		Total
	Farley 2021 Budget	Hatch 2021 Budget	Budget	Budget	
Jan 19 / Jan 19	\$ 5,836,904	\$ 5,836,904	\$ 5,836,904	\$ -	\$ 17,510,713
Feb 19 / Feb 19	4,477,032	4,477,032	4,477,032	0	13,431,096
Mar 19 / Mar 19	5,599,421	5,599,421	5,599,421	0	16,798,263
Apr 19 / Apr 19	4,674,801	4,674,801	4,674,801	0	14,024,402
May 19 / May 19	4,917,045	4,917,045	4,917,045	0	14,751,136
Jun 19 / Jun 19	5,012,869	5,012,869	5,012,869	0	15,038,606
Jul 19 / Jul 19	4,368,724	4,368,724	4,368,724	0	13,106,173
Aug 19 / Aug 19	5,087,924	5,087,924	5,087,924	0	15,263,772
Sep 19 / Sep 19	4,074,210	4,074,210	4,074,210	0	12,222,629
Oct 19 / Oct 19	4,975,218	4,975,218	4,975,218	0	14,925,655
Nov 19 / Nov 19	4,781,340	4,781,340	4,781,340	0	14,344,019
Dec 19 / Dec 19	4,233,292	4,233,292	4,233,292	2,116,646	14,816,520
<b>Total</b>	<b>\$ 58,038,780</b>	<b>\$ 58,038,780</b>	<b>\$ 58,038,780</b>	<b>\$ 2,116,646</b>	<b>\$ 176,232,985</b>

### 2022 SNC Plant Basis Allocation to Each Site

Periods	Vogtle 1&2 2022		Vogtle 3 2022		Vogtle 4 2022 Budget	Total
	Farley 2022 Budget	Hatch 2022 Budget	Budget	Budget		
Jan 19 / Jan 19	\$ 5,180,112	\$ 5,180,112	\$ 5,180,112	\$ 2,590,056	\$ -	\$ 18,130,392
Feb 19 / Feb 19	4,012,818	4,012,818	4,012,818	2,006,409	0	14,044,863
Mar 19 / Mar 19	5,018,989	5,018,989	5,018,989	2,509,495	0	17,566,463
Apr 19 / Apr 19	4,159,472	4,159,472	4,159,472	2,079,736	0	14,558,153
May 19 / May 19	4,427,620	4,427,620	4,427,620	2,213,810	0	15,496,670
Jun 19 / Jun 19	4,545,141	4,545,141	4,545,141	2,272,571	0	15,907,994
Jul 19 / Jul 19	3,903,414	3,903,414	3,903,414	1,951,707	0	13,661,950
Aug 19 / Aug 19	4,589,519	4,589,519	4,589,519	2,294,759	0	16,063,316
Sep 19 / Sep 19	3,690,255	3,690,255	3,690,255	1,845,128	0	12,915,893
Oct 19 / Oct 19	4,441,257	4,441,257	4,441,257	2,220,629	0	15,544,400
Nov 19 / Nov 19	4,279,534	4,279,534	4,279,534	2,139,767	0	14,978,368
Dec 19 / Dec 19	3,936,905	3,936,905	3,936,905	1,968,453	1,968,453	15,747,622
<b>Total</b>	<b>\$ 52,185,038</b>	<b>\$ 52,185,038</b>	<b>\$ 52,185,038</b>	<b>\$ 26,092,519</b>	<b>\$ 1,968,453</b>	<b>\$ 184,616,085</b>

Total Impact by Site

	2021 Allocation Assuming No Change in Allocation Factor	2021 Allocation Based on New Allocation Factor	2021 Impact	2022 Allocation Assuming No Change in Allocation Factor	2022 Allocation Based on New Allocation Factor	2022 Impact
Farley	\$ 58,744,328	\$ 58,038,780	(705,549)	\$ 61,538,695	\$ 52,185,038	(9,353,657)
Hatch	58,744,328	58,038,780	(705,549)	61,538,695	52,185,038	(9,353,657)
Vogtle 1&2	58,744,328	58,038,780	(705,549)	61,538,695	52,185,038	(9,353,657)
Vogtle 3	0	2,116,646	2,116,646	-	26,092,519	26,092,519
Vogtle 4	0	0	-	-	1,968,453	1,968,453
Total	\$176,232,985	\$176,232,985	\$0	\$184,616,085	\$184,616,085	\$0

GPC Impact 100% Dollars	
2021	2022
Hatch 1&2	(\$9,353,657)
Vogtle 1&2	(9,353,657)
Vogtle 3	26,092,519
Vogtle 4	1,968,453
Total	\$9,353,657

GPC Impact GPC % Dollars	
2021	2022
Hatch 1&2	(\$353,480)
Vogtle 1&2	(322,436)
Vogtle 3	967,307
Vogtle 4	0
Total	\$291,392

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-13**

**STF-L&A-13-3**

Question:

SNC charges to Georgia Power. Refer to the response to STF-L&A-1-122.

- a. Show a breakout of each of the 2021 amounts by FERC account for (1) Hatch 1&2, (2) Vogtle 1&2, and (3) Vogtle 3.
- b. Show a breakout of each of the 2022 amounts by FERC account for (1) Hatch 1&2, (2) Vogtle 1&2, (3) Vogtle 3, and (4) Vogtle 4.
- c. Explain the "GPC Impact 100% Dollars" designation.

Response:

- a.-b. Please see Attachment STF-L&A-13-3.
- c. The "GPC Impact 100% Dollars" designation represents the full costs allocated to GPC from SNC before any reductions to the allocated costs for billings to the joint owners.

Georgia Power Company  
2021 SNC Allocation Impacts

GPC FERC Account	FERC Account Description	2021 Hatch Units 1&2			2021 Vogtle Units 1&2			2021 Vogtle Unit 3		
		100% Dollars	GPC %		100% Dollars	GPC %		100% Dollars	GPC %	
408	Taxes Other Than Income Taxes	\$ 1,539,673	\$	771,376	\$ 1,539,674	\$	703,631	\$ 56,822	\$	25,968 (a)
426	Donations	339,802		339,802	339,802		339,802	13,932		13,932 (b)
517	Nuc-Oper Supv & Eng	16,605,551		8,319,381	16,605,552		7,588,737	606,104		276,990 (c)
519	Nuc-Coolants & Water	123,512		61,879	123,512		56,445	4,464		2,040 (c)
520	Nuc-Steam Expenses	386,347		193,560	386,347		176,560	14,161		6,472 (c)
524	Nuc-Misc Nuclear Pwr Exp	37,786,825		18,931,199	37,786,824		17,268,579	1,374,645		628,213 (c)
525	Nuc-Rent	143,867		72,077	143,867		65,747	5,200		2,376 (c)
528	Nuc-Maint Supv & Eng	1,113,203		557,715	1,113,204		508,734	41,317		18,882 (c)
<b>Total</b>		<b>\$ 58,038,779</b>	<b>\$</b>	<b>29,246,989</b>	<b>\$ 58,038,781</b>	<b>\$</b>	<b>26,708,236</b>	<b>\$ 2,116,645</b>	<b>\$</b>	<b>974,872</b>

- (a) Please see Exhibit (DPP/SPA/MBR-1, Schedule 1) Page 8, column 4, line 33 "Taxes Other Than Income Taxes" and Attachment STF-L&A-3-29a, page 17, in the Company's response to STF-L&A-3-29 for the exclusion of the GPC % dollars from the Company's revenue requirement in this filing.
- (b) Amounts recorded to FERC 426 are recorded below-the-line and excluded from retail cost of service.
- (c) Please see Exhibit (DPP/SPA/MBR-1, Schedule 1) Page 8, column 4, line 4 "Generation - Fixed" and Attachment STF-L&A-3-29a, page 4, in the Company's response to STF-L&A-3-29 for the exclusion of the GPC % dollars from the Company's revenue requirement in this filing.



Georgia Power Company  
2022 SNC Allocation Impacts

GPC FERC Account	FERC Account Description	2022 Hatch Units 1&2		2022 Vogtle Units 1&2		2022 Vogtle Unit 3		2022 Vogtle Unit 4	
		100% Dollars	GPC %	100% Dollars	GPC %	100% Dollars	GPC %	100% Dollars	GPC %
408	Taxes Other Than Income Taxes	\$ 1,386,064	\$ 694,418	\$ 1,386,064	\$ 633,431	\$ 693,032	\$ 316,716	\$ 52,540	\$ 24,011
426	Donations	300,984	300,984	300,984	300,984	150,491	150,491	13,094	13,094
517	Nuc-Oper Supv & Eng	14,832,472	7,431,069	14,832,472	6,778,440	7,416,231	3,389,217	552,789	252,624
519	Nuc-Coolants & Water	108,147	54,182	108,147	49,423	54,074	24,712	3,984	1,821
520	Nuc-Steam Expenses	344,002	172,345	344,002	157,209	172,001	78,604	12,850	5,872
524	Nuc-Misc Nuclear Pwr Exp	34,119,363	17,093,801	34,119,363	15,592,549	17,059,671	7,796,270	1,291,907	590,402
525	Nuc-Rent	123,500	61,874	123,500	56,440	61,750	28,220	4,550	2,079
528	Nuc-Maint Supv & Eng	970,511	486,226	970,511	443,523	485,255	221,762	36,734	16,788
<b>Total</b>		<b>\$ 52,185,044</b>	<b>\$ 26,294,898</b>	<b>\$ 52,185,044</b>	<b>\$ 24,011,999</b>	<b>\$ 26,092,504</b>	<b>\$ 12,005,991</b>	<b>\$ 1,968,449</b>	<b>\$ 906,691</b>

(a) Please see Exhibit (DPP)/SPA/MBR-1, Schedule 1) Page 10, column 4, line 33 "Taxes Other Than Income Taxes" and Attachment STF-L&A-3-30a, page 17, in the Company's response to STF-L&A-3-30 for the exclusion of the GPC % dollars from the Company's revenue requirement in this filing.

(b) Amounts recorded to FERC 426 are recorded below-the-line and excluded from retail cost of service.

(c) Please see Exhibit (DPP)/SPA/MBR-1, Schedule 1) Page 10, column 4, line 4 "Generation - Fixed" and Attachment STF-L&A-3-30a, page 4, in the Company's response to STF-L&A-3-30 for the exclusion of the GPC % dollars from the Company's revenue requirement in this filing.

EXHIBIT\_\_(RS/RT-27)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-83**

Question:

With regard to incentive compensation, please provide the exact same information, in the same details and format, as provided in the response to STF-RCS-1-71(a) and Attachments STF-RCS-1-71 SCS and STF-HC-1-71 SNC in Docket No. 36989 but applying to the current case' forecasted test year and to each forecast year, 2020-2022.

Response:

- a. Please see Attachment STF-L&A-1-83a and Attachment STF-L&A-1-83b for incentive compensation billed to GPC by SNC and SCS, respectively.
- b. **Performance Pay Program (Annual performance-based compensation)**  
The Performance Pay Program (PPP) is the component of the Company's overall compensation program comprised of annual performance-based compensation. Under the program, the goals are weighted one-third operational goals, one-third business unit financial goals (Net Income for Georgia Power), and one-third earnings per share.

The test period costs for PPP are determined by employees' PPP target opportunity and the PPP Total Goal Performance Factor. The PPP target opportunities are based on the Company's philosophy to provide total compensation at the market median if performance warrants. Total Goal Performance Factors assumed in the calculation of projected PPP cost as included in the 2019 Budget were 100% for GPC, 150% for SCS, and 150% for SNC.

(See relative proportions associated with Goal Performance Factors included in the 2019 Budget below.)

GPC assumptions and calculation:

Operational goals (1/3 weight)	100%
GPC Net Income (1/3 weight)	100%
Southern Company EPS goal (1/3 weight)	<u>100%</u>
<b>Total Goal Performance Factor</b>	<b>100%</b>

*Operational goals include: Safety, Customer Satisfaction, Generation reliability, Plant Vogtle Units 3 & 4 Project Assessment, Transmission reliability, Distribution reliability, and Culture*

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SCS assumptions and calculation:

Operational goals (1/3 weight)	175%
Business unit financial goals (1/3 weight)	175%
Southern Company EPS goal (1/3 weight)	<u>100%</u>
<b>Total Goal Performance Factor</b>	<b>150%</b>

*Operational goals include: Safety, Customer Satisfaction, Generation reliability, Vogtle Units 3 & 4 Project Assessment, Transmission reliability, Distribution reliability, SNC goals, Culture, and other organizational goals*

SNC assumptions and calculation:

Operational goals (1/3 weight)	175%
Business unit financial goals (1/3 weight)	175%
Southern Company EPS goal (1/3 weight)	<u>100%</u>
<b>Total Goal Performance Factor</b>	<b>150%</b>

*Operational goals include: Safety, Nuclear Plant Safety, Nuclear reliability, Vogtle Units 3 & 4 Project Assessment, and Culture*

**Long-Term Performance-based Compensation**

The Company's overall compensation program includes Performance Share Units and Restricted Stock Units that are focused on long-term, performance-based compensation.

The test period costs for long-term performance-based programs are determined by employees' long-term target opportunity. The long-term target opportunities are based on the Company's philosophy to provide total compensation at the market median if performance warrants. The level of achievement was assumed at the target opportunity for each program.

Please refer to the Company's response to STF-L&A-1-82 for descriptions and copies of the Company's performance-based compensation plans.

**Georgia Power Company**  
**Incentive Compensation Billed to GPC From SNC (100%)**

	Test Year	2020	2021	2022
<b><u>PPP</u></b>				
Capital	11,754,894	12,033,178	11,343,540	3,752,023
O&M	25,412,482	25,902,267	27,976,044	35,455,637
Test Period Total	<b>\$ 37,167,377</b>	<b>\$ 37,935,446</b>	<b>\$ 39,319,584</b>	<b>\$ 39,207,660</b>
	68.37%	68.28%	71.15%	90.43%
<b><u>Performance Shares</u></b>				
Capital	1,002,611	959,448	949,963	371,215
O&M	2,126,338	2,035,519	2,163,586	2,832,030
Test Period Total	3,128,949	2,994,967	3,113,549	3,203,245
	67.96%	67.96%	69.49%	88.41%
<b><u>Restricted Stock</u></b>				
Capital	462,728	439,048	427,731	215,788
O&M	794,290	753,643	734,216	956,605
Test Period Total	1,257,018	1,192,692	1,161,947	1,172,393
	63.19%	63.19%	63.19%	81.59%
<b><u>Long-term Total</u></b>				
Capital	1,465,339	1,398,497	1,377,694	587,003
O&M	2,920,629	2,789,162	2,897,802	3,788,634
Test Period Total	<b>\$ 4,385,968</b>	<b>\$ 4,187,659</b>	<b>\$ 4,275,496</b>	<b>\$ 4,375,638</b>

**Georgia Power Company**  
**Incentive Compensation Billed to GPC From SCS**

Company	Test Year (Aug. 2019 - Jul. 2020)				12/31/2020			
	PPP	PSP	Restricted Stock	Total	PPP	PSP	Restricted Stock	Total
<b>Georgia Power Company</b>	<b>\$ 42,968,684</b>	<b>\$ 7,026,664</b>	<b>\$ 2,650,814</b>	<b>\$ 52,646,162</b>	<b>\$ 44,035,413</b>	<b>\$ 6,957,751</b>	<b>\$ 2,552,707</b>	<b>\$ 53,545,871</b>
<b>Allocation of SCS Billings to GPC:</b>								
All Other Accounts	40.55%	18,341,532	2,187,664	820,993	18,892,312	2,123,011	796,156	21,811,479
<b>O&amp;M</b>	<b>59.45%</b>	<b>24,627,153</b>	<b>4,839,000</b>	<b>1,829,821</b>	<b>25,143,101</b>	<b>4,834,740</b>	<b>1,756,551</b>	<b>31,734,392</b>
		\$ 42,968,684	\$ 7,026,664	\$ 2,650,814	\$ 44,035,413	\$ 6,957,751	\$ 2,552,707	\$ 53,545,871
		57.31%	68.87%	69.03%	57.10%	69.49%	68.81%	
<b>Estimated Allocation to Other Accounts:</b>								
Capital / CWIP	84.61%	15,518,403	1,850,938	694,626	15,996,608	1,797,608	674,126	18,468,342
Below the Line	3.25%	595,183	70,990	26,641	595,032	66,866	25,076	686,974
Clearing Accounts	3.72%	682,122	81,359	30,533	709,611	79,742	29,904	819,257
Job Orders & Other	0.05%	8,804	1,050	394	7,737	869	326	8,933
Deferred Debits and Other Asset Accounts	8.38%	1,537,020	183,326	68,799	1,583,325	177,925	66,724	1,827,974
		\$ 18,341,532	\$ 2,187,664	\$ 820,993	\$ 18,892,312	\$ 2,123,011	\$ 796,156	\$ 21,811,479
<b>12/31/2021</b>								
Company	Test Year (Aug. 2019 - Jul. 2020)				12/31/2021			
	PPP	PSP	Restricted Stock	Total	PPP	PSP	Restricted Stock	Total
<b>Georgia Power Company</b>	<b>\$ 44,481,292</b>	<b>\$ 8,662,393</b>	<b>\$ 2,666,375</b>	<b>\$ 55,810,060</b>	<b>\$ 45,255,728</b>	<b>\$ 8,861,049</b>	<b>\$ 2,725,958</b>	<b>\$ 56,842,735</b>
<b>Allocation of SCS Billings to GPC:</b>								
All Other Accounts	39.52%	18,415,303	2,820,716	819,302	18,430,842	2,868,733	851,220	22,150,795
<b>O&amp;M</b>	<b>60.48%</b>	<b>26,065,989</b>	<b>5,841,677</b>	<b>1,847,073</b>	<b>26,824,885</b>	<b>5,992,317</b>	<b>1,874,738</b>	<b>34,691,940</b>
		\$ 44,481,292	\$ 8,662,393	\$ 2,666,375	\$ 45,255,728	\$ 8,861,049	\$ 2,725,958	\$ 56,842,735
		58.60%	67.44%	69.27%	59.27%	67.63%	68.77%	
<b>Estimated Allocation to Other Accounts:</b>								
Capital / CWIP	82.65%	15,220,438	2,331,351	677,161	14,978,769	2,331,423	691,788	18,001,980
Below the Line	3.24%	596,205	91,322	26,525	596,287	92,811	27,539	716,637
Clearing Accounts	4.02%	740,588	113,438	32,949	707,844	110,175	32,691	850,710
Job Orders & Other	0.04%	7,858	1,204	350	7,563	1,177	349	9,089
Deferred Debits and Other Asset Accounts	10.05%	1,850,214	283,402	82,317	2,140,380	333,147	98,852	2,572,379
		\$ 18,415,303	\$ 2,820,716	\$ 819,302	\$ 18,430,842	\$ 2,868,733	\$ 851,220	\$ 22,150,795

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**STF-L&A-3-38**

Question:

STF-L&A-3-37 Refer to [DPP-SPA-MBR-1, Schedule 1 Total Company.xlsx], tabs "Test Period Earnings," "2020 Earnings," "2021 Earnings," and "2022 Earnings." Identify the amounts for each type of incentive compensation in each line item of Operating Expenses for each period for (1) Georgia Power employees, (2) for SCS employees for which cost is charged to Georgia Power, (3) for SNOC employees for which cost is charged to Georgia Power and (4) for any other affiliates that charge or allocate such cost to Georgia Power.

Response:

Please see Attachment STF-L&A-3-38.

GPC EmployeesTest Period202020212022

Line No.	Description	PPP	Performance Shares	Restricted Stock	PPP	Performance Shares	Restricted Stock	PPP	Performance Shares	Restricted Stock
<b>Operating Expenses</b>										
4	Generation - Fixed	\$ 7,962,119	\$ 645,485	\$ 250,879	\$ 7,986,803	\$ 654,475	\$ 253,260	\$ 8,216,963	\$ 705,444	\$ 263,310
5	Generation - Fuel & Variable O&M	\$ 4,535,132	\$ 31,153	\$ 11,142	\$ 4,514,743	\$ 31,587	\$ 11,247	\$ 4,640,525	\$ 34,047	\$ 11,694
6	Affiliated Purchased Power-Non-Fuel	-	-	-	-	-	-	-	-	-
7	Affiliated Purchased Power-Fuel	-	-	-	-	-	-	-	-	-
8	Non-Affiliated Purchased Power-Non-Fuel	-	-	-	-	-	-	-	-	-
9	Non-Affiliated Purchased Power-Fuel	-	-	-	-	-	-	-	-	-
10	System Control & Load Dispatching	\$ 62,464	\$ 10,052	\$ 3,496	\$ 62,649	\$ 10,192	\$ 3,529	\$ 64,141	\$ 10,985	\$ 3,669
11	<b>Total Production</b>	\$ 12,559,715	\$ 686,690	\$ 265,517	\$ 12,564,195	\$ 696,234	\$ 268,036	\$ 12,921,629	\$ 750,476	\$ 278,672
12	Transmission	\$ 4,654,998	\$ 477,923	\$ 171,127	\$ 4,686,323	\$ 484,581	\$ 172,751	\$ 4,830,018	\$ 522,318	\$ 179,608
13	Distribution	\$ 13,151,546	\$ 1,208,855	\$ 449,831	\$ 13,333,479	\$ 1,225,695	\$ 454,098	\$ 13,608,865	\$ 1,321,148	\$ 472,123
14	Customer Accounting	\$ 7,068,563	\$ 640,540	\$ 243,244	\$ 7,122,358	\$ 649,463	\$ 245,551	\$ 7,346,360	\$ 700,041	\$ 255,298
15	Customer Assistance	\$ 2,721,487	\$ 238,861	\$ 23,861	\$ 2,772,563	\$ 245,612	\$ 23,607	\$ 2,857,338	\$ 245,450	\$ 24,450
16	Energy Services	\$ 1,066,242	\$ 391,732	\$ 391,732	\$ 3,497,514	\$ 1,081,096	\$ 395,448	\$ 3,610,171	\$ 1,165,288	\$ 411,145
17	Administrative & General	\$ 7,158,863	\$ 2,477,446	\$ 931,844	\$ 7,359,172	\$ 2,511,958	\$ 940,683	\$ 7,583,773	\$ 2,707,581	\$ 978,024
18	<b>Total O&amp;M</b>	\$ 50,749,209	\$ 7,206,273	\$ 2,687,156	\$ 51,335,604	\$ 7,306,659	\$ 2,712,646	\$ 52,758,152	\$ 7,875,677	\$ 2,820,320

SCS EmployeesTest Period202020212022

Line No.	Description	PPP	Performance Shares	Restricted Stock	PPP	Performance Shares	Restricted Stock	PPP	Performance Shares	Restricted Stock
<b>Operating Expenses</b>										
4	Generation - Fixed	\$ 5,914,747	\$ 845,127	\$ 279,721	\$ 6,101,804	\$ 727,938	\$ 232,475	\$ 6,331,773	\$ 912,533	\$ 240,920
5	Generation - Fuel & Variable O&M	\$ 537,903	\$ 46,101	\$ 4,321	\$ 512,043	\$ 44,436	\$ 4,318	\$ 532,956	\$ 50,856	\$ 4,465
6	Affiliated Purchased Power-Non-Fuel	-	-	-	-	-	-	-	-	-
7	Affiliated Purchased Power-Fuel	-	-	-	-	-	-	-	-	-
8	Non-Affiliated Purchased Power-Non-Fuel	-	-	-	-	-	-	-	-	-
9	Non-Affiliated Purchased Power-Fuel	-	-	-	-	-	-	-	-	-
10	System Control & Load Dispatching	\$ 3,060,367	\$ 182,025	\$ 93,158	\$ 3,095,952	\$ 203,434	\$ 93,423	\$ 3,193,937	\$ 329,777	\$ 96,834
11	<b>Total Production</b>	\$ 9,513,018	\$ 1,073,253	\$ 377,200	\$ 9,709,798	\$ 975,809	\$ 330,216	\$ 10,058,666	\$ 1,292,666	\$ 342,220
12	Transmission	\$ 3,316,628	\$ 561,720	\$ 223,147	\$ 3,393,907	\$ 508,068	\$ 198,843	\$ 3,502,116	\$ 639,818	\$ 205,868
13	Distribution	\$ 1,240,789	\$ 73,046	\$ 38,057	\$ 1,265,672	\$ 82,252	\$ 38,338	\$ 1,310,998	\$ 134,214	\$ 81,676
14	Customer Accounting	\$ 2,306,113	\$ 148,593	\$ 75,242	\$ 2,403,313	\$ 168,777	\$ 76,345	\$ 2,542,114	\$ 272,291	\$ 19,574
15	Customer Assistance	\$ 614,032	\$ 36,281	\$ 18,888	\$ 621,953	\$ 40,612	\$ 18,928	\$ 640,044	\$ 65,745	\$ 14,888
16	Energy Services	\$ 455,500	\$ 27,940	\$ 14,355	\$ 461,704	\$ 31,193	\$ 14,398	\$ 474,932	\$ 49,816	\$ 14,888
17	Administrative & General	\$ 7,181,073	\$ 2,918,167	\$ 1,082,961	\$ 7,286,754	\$ 3,028,028	\$ 1,079,482	\$ 7,537,118	\$ 3,387,128	\$ 1,142,913
18	<b>Total O&amp;M</b>	\$ 24,627,153	\$ 4,839,090	\$ 1,829,821	\$ 25,143,101	\$ 4,834,740	\$ 1,756,551	\$ 26,065,089	\$ 5,841,677	\$ 1,847,073

SNC EmployeesTest Period202020212022

Line No.	Description	PPP	Performance Shares	Restricted Stock	PPP	Performance Shares	Restricted Stock	PPP	Performance Shares	Restricted Stock
<b>Operating Expenses</b>										
4	Generation - Fixed	\$ 25,412,482	\$ 2,126,338	\$ 794,290	\$ 25,902,267	\$ 2,035,519	\$ 753,643	\$ 27,976,044	\$ 2,163,586	\$ 734,216
5	Generation - Fuel & Variable O&M	-	-	-	-	-	-	-	-	-
6	Affiliated Purchased Power-Non-Fuel	-	-	-	-	-	-	-	-	-
7	Affiliated Purchased Power-Fuel	-	-	-	-	-	-	-	-	-
8	Non-Affiliated Purchased Power-Non-Fuel	-	-	-	-	-	-	-	-	-
9	Non-Affiliated Purchased Power-Fuel	-	-	-	-	-	-	-	-	-
10	System Control & Load Dispatching	-	-	-	-	-	-	-	-	-
11	<b>Total Production</b>	\$ 25,412,482	\$ 2,126,338	\$ 794,290	\$ 25,902,267	\$ 2,035,519	\$ 753,643	\$ 27,976,044	\$ 2,163,586	\$ 734,216
12	Transmission	-	-	-	-	-	-	-	-	-
13	Distribution	-	-	-	-	-	-	-	-	-
14	Customer Accounting	-	-	-	-	-	-	-	-	-
15	Customer Assistance	-	-	-	-	-	-	-	-	-
16	Energy Services	-	-	-	-	-	-	-	-	-
17	Administrative & General	-	-	-	-	-	-	-	-	-
18	<b>Total O&amp;M</b>	\$ 25,412,482	\$ 2,126,338	\$ 794,290	\$ 25,902,267	\$ 2,035,519	\$ 753,643	\$ 27,976,044	\$ 2,163,586	\$ 734,216



**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-3**

**STF-L&A-3-41**

Question:

Refer to pages II-396 and II-397 of the Southern Company SEC Form 10-K for 2018. Show in detail how the Georgia Power amounts for each component of PSU, RSU and Stock Option cost recognized in income were determined for each year, 2016, 2017 and 2018.

Response:

Stock-based compensation may be granted through the Omnibus Incentive Compensation Plan to a large segment of Georgia Power employees ranging from line management to executives. Compensation expense equal to the fair value of the award is generally recognized on a straight-line basis over a three-year performance period. Employees become immediately vested in stock options, PSUs and RSUs upon retirement. As a result, compensation expense for employees that are retirement eligible or will become retirement eligible during the vesting period is accelerated and recognized at the grant date for retirement eligible employees and through the date of retirement eligibility for employees that become retirement eligible during the vesting period. Tax benefits are recognized as compensation expense is recognized.

*Performance Share Units (PSU)*

PSUs granted to employees vest at the end of a three-year performance period. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of PSUs granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors. Southern Company has issued three types of PSUs, each with a unique performance goal. These types of PSUs include total shareholder return (TSR) awards based on the TSR for Southern Company common stock during the three-year performance period as compared to a group of industry peers; return on equity (ROE) awards based on Southern Company's equity-weighted return over the performance period; and earnings per share (EPS) awards based on Southern Company's cumulative EPS over the performance period. EPS awards were not granted in 2018.

Compensation expense equal to the fair value of TSR awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among industry peers over the performance period and is recognized over the vesting period without remeasurement.

Compensation expense is equal to the fair values of EPS awards and ROE awards is based on the closing stock price of Southern Company common stock on the date of the grant. Compensation

expense for EPS and ROE awards is adjusted for changes in expected EPS and ROE performance, resulting in total compensation expense for vested EPS awards and ROE awards reflecting final performance metrics.

When vested PSUs are converted to shares of Southern Company common stock current tax benefits are recognized based on the tax effect of the difference between the grant date fair value price versus the conversion date price of the award.

The income statement effects of PSU compensation expense for the three years are as follows:

<b>Performance Share Units</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>
Compensation Expense	15,157,161	9,560,672	11,122,799
Statutory Tax Rate	38.68%	38.68%	25.47%
Tax Benefit	(5,862,675)	(3,697,996)	(2,833,166)
After-tax compensation expense impact	9,294,486	5,862,676	8,289,633

#### *Restricted Stock (RSU)*

Beginning in 2017, employees are granted RSUs in addition to PSUs. One-third of the RSUs granted to employees vest each year throughout a three-year service period. Shares of Southern Company common stock are delivered to employees at the end of each vesting period.

Compensation expense is equal to the fair value of RSUs and based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the RSUs vest each year throughout a three-year service period, compensation cost for RSUs is generally recognized over the corresponding one-, two-, or three-year vesting period.

The income statement effects of RSU compensation expense for the two years are as follows:

<b>Restricted Stock Units</b>	<b>2017</b>	<b>2018</b>
Compensation Expense	2,828,376	2,873,355
Statutory Tax Rate	38.68%	25.47%
Tax Benefit	(1,093,994)	(731,892)
After-tax compensation expense impact	1,734,382	2,141,463

#### *Stock Options*

In 2015, Southern Company discontinued granting stock options and as of December 31, 2017 all stock option awards have vested. Compensation expense equal to the fair value of stock options computed using a Black-Scholes option valuation is generally recognized on a straight-line basis over the three-year vesting period. Compensation expense for employees that are retirement eligible at the grant date or will become retirement eligible during the vesting period is recognized at the grant date for employees that are retirement eligible and through the date of retirement eligibility for those employees that become retirement eligible during the vesting period. Stock option compensation expense was fully recognized by December 31, 2017.

The exercise price for stock options granted equals the stock price of Southern Company common stock on the date of grant. Options expire no later than 10 years after the grant date. As stock options are exercised, tax benefits are recognized based on the tax effect of the intrinsic value (exercise price versus the strike price) of the award.

The income statement effects of stock option compensation and the tax benefit of stock option exercises for the three years are as follows:

<b>Stock Options</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>
Compensation Expense	372,431	40,012	-
Statutory Tax Rate	38.68%	38.68%	-
Tax Benefit	(144,054)	(15,475)	-
After-tax compensation expense impact	228,377	24,537	-

<b>Stock Option Exercise – Tax benefit</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>
Intrinsic Value	18,419,360	13,232,011	1,522,467
Statutory Tax Rate	38.68%	38.68%	25.47%
Tax Benefit of exercise	(7,124,470)	(5,118,042)	(387,798)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-11**

**STF-L&A-11-30**

Question:

Stock-Based Compensation. Refer to the responses to STF-LA-1-82 and STF-LA-3-38 and the table below:

Description	7/31/2020	12/31/2020	12/31/2021	12/31/2022
GPC - directly-incurred - PSP per STF-L&A-1-82d	\$ 8,044,703	\$ 8,156,769	\$ 8,791,991	\$ 9,055,753
O&M Expense Ratio per STF-L&A-1-82d	65%	65%	65%	65%
GPC - directly-incurred - PSP Charged to O&M per STF-L&A-1-82d	\$ 5,258,754	\$ 5,328,290	\$ 5,742,112	\$ 5,910,192
GPC - directly-incurred - PSP Charged to O&M per STF-L&A-3-38	\$ 7,206,273	\$ 7,306,659	\$ 7,875,677	\$ 8,111,950
Difference	\$ (1,947,519)	\$ (1,978,369)	\$ (2,133,565)	\$ (2,201,758)
GPC - directly-incurred - RSU per STF-L&A-1-82d	\$ 3,002,947	\$ 3,031,434	\$ 3,151,762	\$ 3,214,334
O&M Expense Ratio per STF-L&A-1-82d	65%	65%	65%	65%
GPC - directly-incurred - RSU Charged to O&M per STF-L&A-1-82d	\$ 1,963,001	\$ 1,980,240	\$ 2,058,438	\$ 2,097,819
GPC - directly-incurred - RSU Charged to O&M per STF-L&A-3-38	\$ 2,687,156	\$ 2,712,646	\$ 2,820,320	\$ 2,876,312
Difference	\$ (724,155)	\$ (732,406)	\$ (761,882)	\$ (778,494)
Total GPC Directly Incurred Stock-Based Compensation Charged to O&M per STF-L&A-1-82d	\$ 7,221,755	\$ 7,308,530	\$ 7,800,551	\$ 8,008,010
Total GPC Directly Incurred Stock-Based Compensation Charged to O&M per STF-L&A-3-38	\$ 9,893,430	\$ 10,019,306	\$ 10,695,997	\$ 10,988,262
Total Difference Between GPC directly charged Stock-Based Compensation Expense	\$ (2,671,675)	\$ (2,710,775)	\$ (2,895,447)	\$ (2,980,252)

As shown in the table above, after applying the O&M expense ratio of 65% (per Attachment STF-L&A-1-82(d)) the amounts reflected for GPC directly incurred stock-based compensation (performance shares and restricted stock units) charged to O&M, as provided in Attachment STF-L&A-1-82(d), are substantially less than the GPC directly incurred O&M stock-based compensation as provided in the response to STF-L&A-3-38.

- Please explain and reconcile these discrepancies. Identify, quantify and explain each reconciling difference.
- Which amounts accurately reflect the O&M expenses for the PSP and RSU that the Company has used in the test year and in each plan year, 2020 2021 and 2022?
- Is 65% the correct percentage to apply for the expensed portion of PSP and RSU? If not, what percentage should be applied to the PSP and RSU amounts that were listed in the response to STF-L&A-1-82 to derive the O&M expensed portion?

Response:

- The O&M expense ratio of 65% calculated in the Company's response to STF-L&A-1-82 represents a composite O&M percentage of all GPC directly incurred incentive compensation programs (PPP, PSP, and RSU). The amounts provided in the Company's response to STF-L&A-3-38 represents the O&M portion of the GPC directly incurred incentive compensation by individual programs, which have different O&M percentages. Please see Attachment STF-L&A-11-30 for the O&M expense ratios by individual incentive compensation programs for the test year, and each projected year 2020 through 2022.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-11**

- b. The O&M expenses provided in the Company's response to STF-L&A-3-38 are the budgeted expenses for PSP and RSU in the test year and forecasted years 2020 through 2022.
- c. No, the 65% is not the correct percentage to derive the O&M expense portion of PSP and RSU. Please see the Company's response to 'a' above.

Description	Test Period				2020				2021				2022			
	PPP	Performance Shares	Restricted Stock		PPP	Performance Shares	Restricted Stock		PPP	Performance Shares	Restricted Stock		PPP	Performance Shares	Restricted Stock	
Total O&M (from STP-L&A-3-38)	\$ 50,749,209	\$ 7,206,273	\$ 2,687,156		\$ 51,335,604	\$ 7,306,659	\$ 2,712,646		\$ 52,758,152	\$ 7,875,677	\$ 2,820,320		\$ 54,298,876	\$ 8,111,950	\$ 2,876,312	
Total Directly Incurred Incentive Compensation (from STP-L&A-1-82)	\$ 81,721,860	\$ 8,044,703	\$ 3,002,947		\$ 82,736,454	\$ 8,156,769	\$ 3,031,434		\$ 85,213,578	\$ 8,791,991	\$ 3,151,762		\$ 87,764,607	\$ 9,055,753	\$ 3,214,334	
Program O&M Expense Ratio	62%	89.58%	89.48%		62%	89.58%	89.48%		62%	89.58%	89.48%		62%	89.58%	89.48%	
Composite O&M Expense Ratio	65%				65%				65%				65%			

EXHIBIT\_\_(RS/RT-28)

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NO. 42516**

**Data Request No. STF-L&A-1-82**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS A TRADE SECRET**

As part of Georgia Power's 2019 Rate Case filed in Docket No. 42516, Georgia Power Company (the "Company") submits to the Georgia Public Service Commission (the "Commission") its response to STF-L&A-1-82. In the response, the Company has included incentive target award information (the "Information"). All of such Information constitutes trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. More specifically, the Information contains incentive compensation information that could be used by competitors of the Company, or other companies with which Georgia Power competes for employees, in order to attract employees. Having access to such Information would put Georgia Power at a competitive disadvantage in terms of recruiting and retaining employees. Companies with which Georgia Power competes for employees are not similarly required to disclose incentive compensation information, and disclosure of the Information would artificially alter competition for valuable employees. This would, in turn, harm the Company and its customers in that the Company would be hampered in its attempts to secure and retain qualified employees at all levels of the Company.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company personnel and their legal counsel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.



**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-82**

Question:

With regard to Southern Company's incentive compensation plans, the costs of which are included in GPC's forecasted test year expenses, please provide the following information, similar to the information that was provided in response to STF-RCS-1-70 (and Attachments a, b & c) in the Company's 2013 rate case:

- a. Management summary of the types of incentive compensation programs and a general description of the workings, award criteria and recipient employees of each of these incentive compensation programs.
- b. Copies of actual internal source documentation describing each of these incentive compensation programs.
- c. In total, and broken out by incentive compensation program, provide the costs included in GPC's forecasted test year, also showing what percentage of these costs is charged to O&M expense. Provide this cost information for "direct" GPC incentive compensation, as well as for incentive compensation costs charged and allocated to GPC by SCS and charged and allocated to GPC by SNOC, and charged and allocated to GPC by any other affiliates who have charged or are expected to charge such costs go GPC.
- d. In total, and broken out by incentive compensation program, provide the costs included in GPC's forecasted calendar years, 2020, 2021 and 2022, also showing what percentage of these costs is charged to O&M expense. Provide this cost information for "direct" GPC incentive compensation, as well as for incentive compensation costs charged and allocated to GPC by SCS and charged and allocated to GPC by SNOC, and charged and allocated to GPC by any other affiliates who have charged or are expected to charge such costs go GPC.

Response:

- a. Please see Attachment STF-L&A-1-82a.
- b. Please see Attachments STF-L&A-1-82b and c, which are provided electronically on CD due to volume.
- c-d. Please see Attachment STF-L&A-1-82d.

Attachment STF-L&A-1-82a

**Incentive Compensation Programs General Description**

<b>Program Name</b>	<b>Description</b>
Performance Pay Program	The Company's annual performance program rewards achievement of operational goals, earnings per share and GPC net income. A target percentage of base pay is established for each employee based on his/her classification and grade level for target-level performance. All employees except a small number of sales-commission employees are eligible to participate.
Long-term Incentive Program	The Long-Term Incentive Program is a long-term, target-based, variable pay program for granting equity compensation awards that are paid in shares of common stock of Southern Company. The objective of the Long-Term Incentive Program is to promote strong long-term business results by rewarding continued employment and value drivers that distinguish our performance in the utility industry. Employees classified as exempt under FLSA with a minimum salary range of \$132,299 (Grade 9) or greater are eligible. A long-term performance target percentage of base pay is established for each employee based on his/her grade level. Further, this target percent is allocated between performance share units (70%) and restricted stock units (30%).

**PUBLIC DISCLOSURE**

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# **2019**

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## **Southern Company Long-Term Incentive Program**

## PUBLIC DISCLOSURE

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### **Southern Company Long-Term Incentive (LTI) Program**

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# Southern Company Long-Term Incentive (LTI) Program

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## Program Purpose

The Southern Company Long-Term Incentive Program is a long-term, target-based, variable pay program for granting equity compensation awards that are paid in shares of common stock of Southern Company (Common Stock). Depending on the type of LTI award, vesting is based on continued employment or achievement of specified company performance goals. The objective of the LTI is to promote strong long-term business results by rewarding continued employment and value drivers that distinguish the Southern Company (Southern Company or Company) performance in the utility industry.

## Program Governance

The program is granted pursuant to and governed by the Southern Company Omnibus Incentive Compensation Plan, as amended from time to time (Omnibus Plan). The Omnibus Plan is administered by the Compensation and Management Succession Committee of the Board of Directors of the Southern Company (Committee). This document describes the LTI and may be amended at any time.

LTI awards are subject to the terms and conditions set forth in the Omnibus Plan, this document, any other administrative documents adopted by the Committee from time to time and the LTI award agreement. In case of any conflict between the provisions of the Omnibus Plan and this document, the provisions of the Omnibus Plan will govern.

This document summarizes the terms and conditions of the LTI for eligible employees of Southern Company and its subsidiaries (except for Sequent, SouthStar, and PowerSecure).

## Timing of Grants

- **Annual grants** – LTI awards are granted on an annual basis, typically in February of each year, to eligible participants.
  - A participant must be in an eligible position on the date of the grant and the annual merit pay increase date to be eligible to receive an annual grant under the LTI.
  - In 2019, the date of the annual grant is February 11, 2019 and the date of the annual merit increase is March 1, 2019.
- **Midyear grants** - Prorated LTI awards are granted on August 1 to new hires and employees promoted from ineligible positions into eligible positions between the February annual grant date and August 1.
  - Midyear grants are equal to 50% of the annual target grant amount.
  - Eligible participants promoted to a higher position or salary grade level after the annual grant are not eligible for an additional grant during the midyear grant process.

## Participant Eligibility

A participant must meet all of the following criteria to be eligible to participate in the LTI.

- The participant must be classified as an exempt employee.
- The participant must be an employee of a Southern Company subsidiary (a) on the date of the grant and the date of the annual merit increase (for the annual grant) or (b) on August 1 (for the midyear grant).
- The participant must be employed in an eligible salary grade level (grade 9 or above) (a) on the date of the grant and the date of the annual merit increase (for the annual grant) or (b) on August 1 (for the midyear grant).

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Certain employment events impact eligibility for LTI grants. See **Appendix A: Additional Terms of Participation and Payout Eligibility**.

Eligibility requirements noted above must be effective in the human resource information system (SHIPS) on the date of the grant. Eligibility will not be retroactively applied.

The following employees and other persons are not eligible for the LTI (even if the employee's classification within a group is determined to have been incorrect):

- Non-exempt employees or bargaining unit employees
- Exempt employees in salary grades 8 or below
- Independent contractors or leased employees
- Co-ops, interns, and temporary employees
- Employees working for a Southern Company subsidiary covered under a different long-term incentive plan or program
- Employees with an alternative compensation arrangement in place that precludes participation in the LTI

### LTI Target Award Percentage and Target Grant Value

Once eligibility is established, a participant's LTI target award percentage is determined by their position or salary grade level on the grant date for the annual grant, or on August 1 for the midyear grant.

The LTI target grant value is calculated using Base Salary on (a) the date of the annual merit increase for the annual grant or (b) August 1 for the midyear grant, multiplied by the LTI target award percentage (and multiplied by 50% for the midyear grant).

See **Appendix B: Glossary of Terms** for a definition of Base Salary.

### LTI Program Components

Two types of LTI awards are granted to eligible participants: Restricted Stock Units (RSUs) and Performance Share Units (PSUs).

- **RSUs** are stock units that vest over a defined period of time based solely on continued employment. Upon vesting, RSUs convert to shares of Common Stock on a one for one basis.
  - The vesting of RSUs is not subject to company performance measures except for the RSUs awarded to the executive officers of Southern Company (Executive Officers).
  - The value of RSUs can increase or decrease depending on the change in the Common Stock price from the date of grant to the time of vesting.
  - RSUs granted in 2019 will vest one-third each year on the anniversary of the grant date, over the course of three years.
- **PSUs** are stock units that vest at the end of a defined performance period and convert to shares of Common Stock based on achievement of specific performance measures that will be calculated at the end of the performance period upon vesting.
  - PSUs granted in 2019 will vest at the end of a three-year performance period from January 1, 2019 to December 31, 2021 based on achievement of two performance measures: total shareholder return (TSR) relative to industry peers and return on equity (ROE), subject to satisfaction of a credit quality threshold goal.

For all eligible employees except for the Company's Chief Executive Officer (CEO), the RSUs and PSUs

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represent 30% and 70% of the overall awards respectively. For the Company's CEO, the RSUs and the PSUs represent 25% and 75% of his overall award respectively.

The LTI awards granted to the Executive Officers have certain additional terms and conditions noted throughout this document.

### Form and Timing of Payout

- **RSUs:** RSU awards vest one-third each year on the anniversary of the grant date and will be paid in unrestricted shares of Common Stock as soon as practical following each vesting date but in no event later than 30 days following the applicable vesting date.
- **PSUs:** PSU awards vest on the last day of the performance period and will be paid in unrestricted shares of Common Stock as soon as practical following the end of the performance period, but in no event later than March 15 immediately following the end of the performance period. If the performance goals are not met, then no performance shares are paid out.

Vested RSU and PSU payouts are subject to applicable withholding taxes. For purposes of tax calculations, the value of the vested Common Stock will be determined based on the Fair Market Value (as defined in the Omnibus Plan) of the closing stock price on the applicable vesting date for RSUs and on the final date the results of the performance metrics are certified by the Committee for PSUs. The actual number of shares received will be reduced by the number of shares reflecting the amount of withholding taxes. Traditional rounding is used to determine the number of shares granted. Shares are rounded up to the nearest whole share when awarded.

Participants in the Southern Company Deferred Compensation Plan may not defer receipt of LTI payouts.

### Underpayments/Overpayments

If there is an error in the determination of a payout amount (regardless of why the error occurs) or in the payment of a payout or a recalculation of the performance results (whether due to misconduct or otherwise), Southern Company, in its sole discretion, shall determine the method for correcting the error in accordance with the requirements of the Omnibus Plan. If the error results in an overpayment, Southern Company may choose, among other options, to require repayment of the overpayment or to reduce future payouts.

### Committee Discretion

The Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts.

### Other Terms

LTI awards may not be assigned or transferred for any reason, including transfers incident to a divorce. Any attempt to assign or transfer the right to payments from this program shall be void and have no effect.

No employment rights are created by this program or the Omnibus Plan.

LTI payouts are not considered pay for purposes of any other plan.

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### Restricted Stock Units

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#### Determining Number of RSUs Granted

To calculate the number of RSUs to be granted, the RSU target grant value (Base Salary x LTI Target Award % x LTI RSU Component %) is divided by the closing price of the Common Stock on the grant date. For the annual grant, salary grade level is determined as of the grant date and Base Salary is determined as of the date of the annual merit increase. For the midyear grant (50% of the annual target grant amount), salary grade level and Base Salary are determined as of August 1.

The participant will be notified of the number of RSUs that have been granted.

#### Dividends

All dividends accumulated on Common Stock during the vesting period are added to the number of RSUs granted and treated as reinvested in additional RSUs until each amount vests and is paid out.

#### Vesting Schedule

RSUs vest one-third annually, on each anniversary of the grant date, over the course of three years. Participants must have continuously remained an employee of a Southern Company subsidiary from the grant date to each vesting date for RSUs to vest.

There are certain exceptions to this continuing employment requirement, including retirement, death and disability. In addition, termination for cause creates an exception to the vesting rule. Such a termination results in forfeiture of any unpaid award, even if it is vested. See **Appendix A: Additional Terms of Participation and Payout Eligibility**.

#### Example of RSU Payout Calculation

The actual value of the RSUs that vest one-third each year will vary from the target value of the RSUs as the value of Common Stock increases or decreases from the closing price on the date of grant. The actual number of RSUs that vest each year will vary from the specific number of RSUs originally granted due to the accrued and reinvested dividends associated with the specific number of RSUs originally granted.

The following is an example of how the RSU payout will be calculated over the vesting period for the award.

- On February 11, 2019 and March 1, 2019 an eligible participant is in salary grade REDACTED LTI Target Award Percentage REDACTED | has a Base Salary rate of REDACTED
  - The participant's RSU grant value REDACTED (Base Salary of REDACTED x LTI Target Award % of REDACTED RSU Component % of REDACTED
- To determine the number of RSUs granted, the RSU grant value is divided by the closing price of the Common Stock on the grant date, which we assume is REDACTED
  - :REDACTED | = REDACTED
- Therefore, this participant would be granted REDACTED that would vest one-third annually on the anniversary of the grant date, over the course of three years.



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Vesting Date	February 11, 2020	February 11, 2021	February 11, 2022
# of Vested RSUs	1/3 RSUs REDACTED dividends	1/3 RSUs REDACTED dividends	1/3 RSUs REDACTED dividends
Value of RSUs	REDACTED  (+ value of reinvested dividends)	REDACTED  (+ value of reinvested dividends)	REDACTED  (+ value of reinvested dividends)

- If the Fair Market Value (as defined in the Omnibus Plan) of a share of Common Stock on each vesting REDACTED then the value of the RSUs that vest on each vesting date will be REDACTED REDACTED (depending on how many RSUs vest as described above) plus the value of the reinvested dividends. This amount will be reported as W-2 earnings to the participant.
- At each vesting date, shares will be withheld to pay withholding taxes due on the value of the vested amount.

### Additional Terms Applicable to Executive Officers

RSUs for Executive Officers include a performance requirement (RSU Performance Goal). The RSU Performance Goal will apply for the calendar year of the date of the grant and will be set by the Committee within the first 90 days of the calendar year. The RSU Performance Goal will be one of the financial performance measures set forth in Article 10 of the Omnibus Plan. The RSU Performance Goal for 2019 is as follows:

2019 RSU Performance Goal	
Cash from Operations	Greater than \$2.425B (2018 Dividends Paid)

No later than 60 days after the end of the calendar year of the grant, the Committee shall determine whether the RSU Performance Goal was met and shall certify such attainment (Certification Date). If the RSU Performance Goal is not attained, all RSUs under the grant shall be forfeited by the Executive Officers as of the Certification Date.

RSUs for Executive Officers will vest as follows:

Amount	Vesting Date
1/3 of RSU Award	Certification Date
1/3 of RSU Award	2-Year Anniversary of Grant Date
1/3 of RSU Award	3-Year Anniversary of Grant Date

## Performance Share Units

### Determining Number of PSUs Granted

To calculate the number of PSUs to be granted to a participant, the target amount (Base Salary x LTI Target Award % x PSU Component %) is divided by the closing price of the Common Stock on the date of the grant. For the annual grant, salary grade level is determined as of the grant date and Base Salary is determined as of the date of the annual merit increase. For the midyear grant (50% of the annual target grant amount), salary grade level and Base Salary is determined as of August 1.

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The participant will be notified of the number of PSUs that have been granted for each PSU performance measure.

### Performance Measures and Weighting

Performance measures are established by the Committee on the date of grant. PSUs granted in 2019 will vest at the end of a three-year performance period based on achievement of performance measures of total shareholder return (TSR) relative to Southern Company industry peers and return on equity (ROE), as well as achievement of the credit quality threshold goal described below.

For the Company's CEO, there is an additional performance measure based on the Company's goal to reduce Greenhouse Gas (GHG) emissions by 50% by 2030 and to be low- to no-carbon emission by 2050.

**For all eligible employees (except CEO):**

PSU Components (70% of Overall LTI Award)	
PSU Measure	LTI Weighting
Relative TSR	40%
ROE	30%

**For the Company's CEO:**

PSU Components (75% of CEO's LTI Award)	
PSU Measure	LTI Weighting
Relative TSR	40%
ROE	25%
GHG Reduction	10%

### Relative TSR

- TSR measures investment gains arising from stock price appreciation and dividends received from that investment. TSR performance is measured for Southern Company and each of the peer group companies during the performance period. Southern Company's TSR is ranked against the TSR for each of the peer group companies to determine performance on this measure.
- The peer group is established by the Committee for during the beginning of the performance period. The peer group stays constant during the performance period, except for the impact of mergers and acquisitions. To be counted in the final calculation, a company must be in the peer group at both the beginning and the end of the performance period. If a peer company is acquired by a non-peer company during the performance period, the peer is removed from the peer group. If a peer company is the target of an announced, but not yet closed, acquisition by a peer or a non-peer company during the performance period, the peer is removed from the peer group. If a peer company acquires a non-peer company during the performance period, no adjustments are made and the peer company remains in the peer group. The Committee in its discretion may add or delete companies from the peer group during the performance period to the extent that it deems it appropriate.
  - For the 2019 grant, the Committee has established the following peer group and payout matrix for the 2019 to 2021 performance period.

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Peer Group		
AEP	Duke	OGE
Alliant	Edison Intl.	Pinnacle West
Ameren	Entergy	PPL
Centerpoint	Eversource	Sempra
CMS	Evergy	Wisconsin
ConEd	FirstEnergy	Xcel
DTE	Fortis	

Relative TSR Payout Matrix	
Percentile of 3-Year SO TSR vs. Peer Group	TSR Payout
90 <sup>th</sup>	200%
50 <sup>th</sup>	100%
At or below 10 <sup>th</sup>	0%

- Average price is used for beginning and end points to mitigate daily market volatility
- Performance between points is interpolated

## ROE

- ROE measures consolidated Company ROE from all electric and gas operations (including Southern Company Gas and Southern Power) over the 2019 to 2021 performance period.
- The calculation of ROE excludes potential costs associated with plants under construction, acquisition, disposition, and integration costs, earnings from Wholesale Gas Services, and one-time items related to corporate transactions (i.e. acquisitions and/or divestitures).

ROE Payout Matrix	
Performance Level	ROE Payout
12.5%	200%
10.5%	100%
9.0%	0%

- Performance between points is interpolated

## Credit Quality Threshold Goal

The ROE measure described above is subject to a credit quality threshold goal established by the Committee at the time of the grant. If, at the end of the performance period, the credit ratings for Southern Company, Alabama Power Company (APC) and Georgia Power Company (GPC) are below the following specified levels approved by the Committee, there will be no payout associated with the ROE measure for all employees:

- Southern Company is rated below BBB – by Standard & Poor's
- APC is rated below BBB/Baa2 by both Fitch and Moody's
- GPC is rated below BBB/Baa2 by both Fitch and Moody's

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### GHG Emission Reduction

The GHG emission reduction goal has two main objectives:

- 1) **Primary objective:** Create accountability to achieve our 2030 commitment of 50% reduction in GHG emissions:
  - ✓ The range of potential payout percentages for the 2019-2021 performance share units is 0% to 150%. Performance is measured against our plan to achieve 50% GHG reduction by 2030 and defined in terms of net megawatt changes (i.e. a combination of adding zero carbon MWs and placing coal MWs in inactive reserve or retirement status)

GHG Emission Reduction Goal Payout for Performance Period 2019 - 2021		
Net MW Change	Payout % of Target	Estimated % Complete of 50% Carbon Reduction Goal by 2021
< 2,204 MW	0%	42%* of 50% Commitment
2,641 MW	50%	43%
3,080 MW	100%	44%
3,518 MW	150%	45%

\* Represents the % of carbon emission reduction goal completed

\* GHG reduction goal is 50% reduction by 2030 (as compared to 2007 baseline); LTI goal will be expressed in MW changes (not all MW are GHG equal)

\* Payout is interpolated between performance ranges

- 2) **Secondary objective:** Provide a qualitative assessment to evaluate our progress toward our low to No carbon objective

Payout modifier assessment (up to 30%) will be based on the Committee's assessment of the CEO's leadership of the Company's progress on advancing the energy portfolio of the future (e.g. research and development investments, energy policies, renewable investments, innovation, etc.)

Achievement	Modifier
Fails to meet	0%
Meets	+15%
Exceeds	+30%

### **Dividends**

All dividends accumulated on Common Stock during the performance period are added to the number of target PSUs and treated as reinvested in additional PSUs. Reinvested dividends will not be paid out until the underlying PSU award is paid out after the end of the performance period and will depend on Company achievement of the performance measures. If no PSUs are earned and paid out, no dividends will be paid out. Any dividends paid out will be paid in shares of Common Stock.

### **Vesting Schedule**

PSUs vest December 31 of the last year in the performance period. The performance period for the PSU portion of the 2019 LTI is the three-year period from January 1, 2019 through December 31, 2021.

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Participants must have continuously remained an employee of a Southern Company subsidiary from the grant date to the last day of the performance period for PSUs to vest. There are certain exceptions to this continuing employment requirement, including retirement, death and disability – see **Appendix A: Additional Terms of Participation and Payout Eligibility**. In addition, termination for cause creates an exception to the vesting rule. Such a termination results in forfeiture of any unpaid award, even if it is vested.

### Example of PSU Payout Calculation

The actual number of and value of PSUs that vest will vary from the target number of and value of PSUs granted based on Company performance and the change in the value of the Common Stock from the date of grant to the date any payout is made. The actual number of PSUs that vest will also vary due to the accrued and reinvested dividends over the performance period.

The following is an example of how the PSU payout will be calculated.

- On February 11, 2019 and March 1, 2019 an eligible participant is in is in salary REDACTED with a LTI Target Award Percentage of REDACTED has a base salary rate of REDACTED
  - The participant's total PSU target grant value is REDACTED  
LTI Target Award of REDACTED PSU Component % REDACTED
- Assume the Common Stock closing price of the relative TSR portion of the PSU grant is \$44 based on the expected relative TSR on the date of grant and the fair value of the ROE component of the PSU is \$44, which is the Common Stock closing price on the date of grant.
- On February 11, 2019, the participant is granted a target PSU award as follows:
  - REDACTED PSUs based on relative TSR REDACTED
  - REDACTED PSUs based on ROE REDACTED
  - REDACTED = Total PSUs granted to participant
- Assume Southern Company's performance against the pre-established measures for the performance period ending December 31, 2021 is REDACTED relative TSR and REDACTED ROE.
- Assume the value of accrued and reinvested dividends associated with the target number of PSUs over the performance period is + REDACTED
- The participant will be entitled to a payout of REDACTED of Common Stock if the participant remains employed until the date of payout.
  - REDACTED
  - REDACTED
- Assuming the Fair Market Value (as defined in the Omnibus Plan) on the approval date is \$50, then the estimated value of the PSU payout on that date will be REDACTED  
This amount will be reported as W-2 earnings to the participant.
- Shares will be withheld to pay withholding taxes due on the value of the vested amount.

### Additional Terms Applicable to Executive Officers

For Executive Officers, the Committee determines the final payout and any associated exclusions from the calculation of the performance measures and retains discretion to exercise negative discretion to reduce the amount of the payout. All other terms and conditions apply to the PSUs for Executive Officers.

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**Appendix A**

**Additional Terms of Participation and Payout Eligibility**

Employment Event	Eligibility for Grants after Employment Event	Vesting/Payout of LTI Grants	
		RSUs	PSUs
New hire, rehire or promotion after annual grant date	<p>Midyear grants (50% of the annual target grant amount) will be made on August 1 to new hires, rehires and employees promoted from ineligible positions into eligible positions between the February annual grant date and August 1</p> <p>Eligible participants that received an annual grant and are promoted to a higher LTI target between the February annual grant date and August 1 are not eligible for an additional grant during the midyear grant process</p>	<p>Vesting schedule is 1/3 on the anniversary of the grant date, over the course of three years</p> <p>Payout terms same as active employee</p>	<p>Vest at the end of the three-year performance period based on actual performance</p> <p>Payout terms same as active employee</p>
Demotion to ineligible position after annual grant or midyear grant	<p>No additional grants after demotion into ineligible position</p> <p>No impact on LTI grants made prior to demotion</p>	<p>No impact; RSUs granted prior to demotion follow vesting schedule of 1/3 on each anniversary of the grant date, over the course of three years</p> <p>Payout terms same as active employee</p>	<p>No impact; PSUs granted prior to demotion vest at the end of the three-year performance period based on actual performance</p> <p>Payout terms same as active employee</p>
Termination of employment due to Retirement <sup>1</sup>	No	<p>No proration; RSUs granted prior to Retirement follow vesting schedule of 1/3 on each anniversary of the grant date, over the course of three years</p> <p>Payout terms same as active employee</p>	<p>No proration; PSUs granted prior to Retirement vest at the end of the three-year performance period based on actual performance</p> <p>Payout terms same as active employee</p>



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Employment Event	Eligibility for Grants after Employment Event	Vesting/Payout of LTI Grants	
		RSUs	PSUs
Termination of employment due to Death <sup>2</sup>	No	No proration; accelerated vesting of remaining unvested RSUs granted prior to death  Payable within 30 days after death	Prorated payout; PSUs granted prior to death vest at the end of the three-year performance period based on actual performance  Payout is prorated based on number of months employed during the performance period
Termination of employment due to Disability <sup>3</sup>	No	No proration; accelerated vesting upon termination of employment of remaining unvested RSUs granted prior to Disability  Payable within 30 days after termination date due to Disability notification	Prorated payout; PSUs granted prior to Disability vest at the end of the three-year performance period based on actual performance  Payout is prorated based on number of months employed during the performance period, including time on leave of absence
Paid leave of absence	No impact; remain eligible for LTI grants, so long as employee meets all other eligibility requirements for annual or midyear grant	Vesting schedule is 1/3 on the anniversary of the grant date, over the course of three years  Payout terms same as active employee	Vest at the end of the three-year performance period based on actual performance  Payout terms same as active employee
Military leave of absence, unpaid leave of absence or disability <sup>3</sup>	No additional grants after date of event; eligibility will be renewed upon return from leave of absence, assuming all other eligibility criteria are met  No impact on LTI grants made prior to date of event	Vesting schedule is 1/3 on the anniversary of the grant date, over the course of three years  Payout schedule same as active employee	Vest at the end of the three-year performance period based on actual performance  Payout schedule same as active employee
Any termination for cause on or before date of payout	No	Forfeit vested but unpaid RSUs and all unvested RSUs	Forfeit vested but unpaid PSUs and all unvested PSUs
Any other type of termination not for cause <b>on or before</b> applicable vesting date	No	Forfeit all unvested RSUs	Forfeit all unvested PSUs

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Employment Event	Eligibility for Grants after Employment Event	Vesting/Payout of LTI Grants	
		RSUs	PSUs
Any other type of termination not for cause after applicable vesting date but prior to payout	No	Forfeit all unvested RSUs  No change to payout schedule for vested RSUs	Forfeit all unvested PSUs  No change to payout schedule for vested PSUs

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<sup>1</sup> Retirement is any allowed retirement under the Southern Company Pension Plan.

*If retirement is in lieu of a termination for cause or if the participant is not eligible for rehire, there will be no payout.*

<sup>2</sup> LTI payouts will be paid to the participant's estate or the entity or individual authorized to receive the payments under the participant's will or the laws of intestate succession.

<sup>3</sup> Per the Omnibus Plan, Disability is defined under the Company governing long-term disability plan or, if no such plan exists, at the discretion of the Committee



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**Appendix B**

**Glossary of Terms**

<b>Base Salary</b>	<p>Base Salary is defined as your annual base rate (excluding premiums, bonuses, overtime, shift differential and substitution pay) on the date of the annual merit increase of the performance year. In cases of the midyear grant, Base Salary is defined as your annual base rate (excluding premiums, bonuses, overtime, shift differential and substitution pay) on August 1 of the grant year.</p> <p>The base rate is not reduced by any of the following:</p> <ul style="list-style-type: none"><li>• Taxes</li><li>• Social Security</li><li>• Amounts contributed on a participant's behalf to the flexible benefits plan or the Southern Company Employee Savings Plan (as an elective employer contribution per Section 4.1 therein)</li><li>• If applicable, amounts the participant has deferred through the after-tax portion of the Southern Company Employee Savings Plan or through the Southern Company Deferred Compensation Plan</li></ul>
<b>Disability</b>	<p>Per the Omnibus Plan, disability is defined under Southern Company's governing long-term disability plan or, if no such plan exists, at the discretion of the Committee.</p>
<b>Leave of Absence</b>	<p><b>Paid Leave of Absence</b> – includes maternity/parental, adoption and any FMLA certified as paid leave of absence.</p> <p><b>Unpaid Leave of Absence</b> – includes personal leave and any FMLA certified as unpaid leave</p>
<b>Prorate/Proration</b>	<p>If an award is prorated based on the number of months worked by an employee, the employee is considered to have worked the entire month if he or she is employed for at least one day in the month.</p>

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<b>Termination for cause</b>	<p>A termination for cause includes any type of termination (including, but not limited to, a voluntary or involuntary resignation by a participant, a voluntary or involuntary termination by the Company, a termination with severance, a participant's retirement, or a participant's termination because of a disability) if such termination is related to cause.</p> <p>"Cause" includes, but is not limited to, the following:</p> <ul style="list-style-type: none"><li>• The final conviction of a felony or misdemeanor involving moral turpitude.</li><li>• Determined to have perpetrated any act involving fraud or dishonesty or breach of appropriate regulations of competent authorities.</li><li>• The carrying out of any activity or the making of any statement which would prejudice the good name and standing of Southern Company or subsidiary of Southern Company (collectively, the "Companies") or would bring the Companies into contempt or ridicule or would reasonably shock or offend any community in which the Companies are located.</li><li>• Violation of an applicable company drug and alcohol policy.</li><li>• In the event there is no drug and alcohol policy, attendance at work in a state of intoxication or otherwise being found in possession at workplace of any prohibited drug or substance, possession of which would amount to a criminal offense.</li><li>• Assault or other act of violence against any employee or other person during the course of employment.</li><li>• A material breach of the fiduciary obligations owed by an officer and an employee to the Companies.</li><li>• Unsatisfactory performance of the duties and services required by the employee's employment.</li></ul>
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# 2019

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## Southern Company Performance Pay Program (PPP)

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## Southern Company 2019 Performance Pay Program

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### Program Purpose

The Southern Company Performance Pay Program (PPP) is an annual, target-based, variable-pay program that pays out in cash. It sets thresholds, targets, and maximums for each participant and pays out dependent on corporate, business unit, and individual performance relative to established goals.

Payouts are based on financial performance, including Southern Company earnings per share (EPS), net income or other financial goals at the business units/operating companies, and operational performance, including safety, operations, culture, and other goals specific to each business unit/operating company. The objective of the PPP is to promote strong short-term business results by rewarding value drivers on an annual basis for each business unit/operating company.

### Program Governance

The program is granted pursuant to and governed by the Southern Company Omnibus Incentive Compensation Plan, as amended from time to time (Omnibus Plan). The Omnibus Plan is administered by the Compensation and Management Succession Committee of the Board of Directors of the Southern Company (Committee). This document describes the PPP and may be amended at any time. In case of any conflict between the provisions of the Omnibus Plan and this document, the provisions of the Omnibus Plan will govern.

PPP awards for the executive officers of Southern Company (Executive Officers) have certain additional terms and conditions that are separately described.

### Participant Eligibility

All regular full-time and part-time employees are eligible to participate in the PPP if in an eligible position as of December 31 of the performance period, except as described below. Collective bargaining employees only participate to the extent their bargaining units have approved participation.

Employees of Southern Company Gas should refer to the Southern Company Gas PPP plan document.

The following employees and other persons are not eligible to participate in the PPP (even if such classification is determined to have been incorrect):

- Independent contractors
- Temporary employees
- Leased workers
- Service vendor workers
- Co-ops and interns
- Employees working for a Southern Company subsidiary that has a different short-term incentive plan, commission program or sales incentives plan, including PowerSecure, Inc.
- GPC bargaining unit employees who have not completed their probationary period and who are not approved by their manager to participate as of December 31

See **Appendix A: Additional Terms of Participation and Payout Eligibility** for additional details on terms of eligibility (including retirement, resignation and those not eligible to participate).

### Performance Period and Payment of Awards

The performance period for the PPP is January 1 through December 31. PPP awards vest on December 31 of the performance period. Participants must be employed on that date to be eligible to receive a payout for the year, except in cases of retirement, disability or death. See **Appendix A: Additional Terms of Participation and Payout Eligibility** for additional details on payment of awards.

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Payments are made in cash as soon as practicable after the end of the performance period, but no later than March 15 of the year following the performance period.

PPP payouts are taxable to participants in the year received. Payouts are subject to the following tax withholdings: Federal (flat rate), Social Security, Medicare, and State and local taxes where applicable. Payroll deductions are limited to legal withholdings (i.e. garnishments, child support, levies and bankruptcies).

## Underpayments/Overpayments

If there is an error in the determination of a payout amount (regardless of why the error occurs) or in the payment of a payout or a recalculation of the performance results (whether due to misconduct or otherwise), Southern Company, in its sole discretion, shall determine the method for correcting the error in accordance with the requirements of the Omnibus Plan. If the error results in an overpayment, Southern Company may choose, among other options, to require repayment of the overpayment or to reduce future payouts.

## Impact on Other Plans - PPP Treatment in Other Southern Company Plans<sup>1</sup>

- **Pension Plan** – Counts actual PPP payouts as pay for certain formulas as defined under the plan
- **Employee Savings Plan** – Does not count PPP payouts as pay for determination of employer matching contribution but PPP payouts are counted as pay that may be deferred
- **Life Insurance Plan** – Does not count PPP payouts as pay
- **Long-Term Disability** – Does not count PPP payouts as pay
- **Supplemental Individual Disability Insurance** – If the employee is eligible and elects coverage, PPP payouts are factored into the total compensation covered
- **Deferred Compensation Plan** – If the employee is eligible, PPP payouts are counted as pay that may be deferred but are not eligible for employer matching contributions

## Other Terms

Payments from this program are not subject to assignment or transfer for any reason, including transfers incident to a divorce. Any attempt to assign or transfer the right to payments from this program shall be void and have no effect.

No employment rights are created by this program or the Omnibus Plan.

## Terms Applicable to Executive Officers

Certain additional requirements applicable to the Executive Officers are as follows:

- An objective, performance-based payout formula is set by the Committee within the first 90 days of the performance period. It must be clear enough that an outside third party, with knowledge of all the facts, could calculate the payout.
- Actual performance must be certified by the Committee prior to payout.
- Only negative discretion may be applied to reduce the payout from the amount determined under the formula.

<sup>1</sup> Every effort has been made to ensure the accuracy of the information provided above. However, in the event there is a discrepancy between the information provided in this document and the benefits to which you are entitled, the terms of the applicable plan document will govern the determination of any benefits you are eligible to receive. Your actual benefits will be determined based upon the applicable plan document.

## Plan Design

Goals are set for each performance period using the performance measures most important to Southern Company and each operating company/business unit. For 2019, the PPP has the following performance goals and weightings which vary depending upon your participant group.

2019 Performance Goals and Weightings				
Participant Group	Corporate EPS Goal	Business Unit Financial Goal	Business Unit Operational Goal	Individual Performance Goal
<b>Southern Company CEO &amp; CFO</b>	45%	0%	30%	25%
<b>Southern Company Management Council and Grade 11+</b>	25%	25%	30%	20%
<b>All Other Participants</b>	1/3	1/3	1/3	0%

The Committee may approve exceptions to the performance goals. The primary considerations for an exception include adjustments to exclude the up or down impact of items: (1) considered “one time” or outside of “normal operations;” (2) not anticipated in the business plan when the goal was established; and (3) of sufficient magnitude to warrant recognition.

### Funding Threshold (Dividend Funding Mechanism)

Southern Company EPS must exceed the prior year dividend to provide any PPP opportunity for the performance components (dividend funding mechanism). The intent of the dividend funding mechanism is to ensure adequate coverage of dividend payments and to eliminate PPP payouts under circumstances that prevent or threaten continuation of the dividend at the prior year’s level. The dividend funding mechanism is not intended to activate when non-recurring, non-cash items occur. In situations where EPS does not exceed the prior year dividend but Southern Company’s earnings are sufficient to fund the dividend, the PPP payout will not be affected by this provision.

## Corporate Performance Component

### Southern Company EPS Performance Range

EPS is measured as basic earnings per share from continuing operations. EPS is calculated by dividing the consolidated net income from continuing operations by the average shares outstanding for 2019. For PPP purposes, the 2019 EPS measurement excludes potential costs associated with plants under construction, acquisition, disposition, and integration costs, earnings from Wholesale Gas Services, and one-time items related to corporate transactions (i.e. acquisitions and/or divestitures).

The Southern Company EPS goal payout range for all participants is 0% to 200% of target. PPP goal performance will be determined using the following scale. Results will be interpolated on a straight-line basis when they fall between performance levels.

	Corporate Performance	2019 EPS
Maximum	200%	\$3.19
	150%	\$3.10
Target	100%	\$3.04
	50%	\$2.98
Threshold	0%	\$2.89

## Business Unit Financial Component

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### Business Unit Net Income

The business unit financial goal is net income after dividends on preferred and preference stock, if applicable. For Southern Company Services, Inc. (SCS), the business unit financial goal performance is determined by the equity-weighted average of the business unit net income goal payouts. For Southern Nuclear Operating Company, Inc. (SNC), the business unit financial goal performance is determined by the average payout for the APC and GPC net income goals. For PPP purposes, the 2019 business unit financial goal measurement excludes estimated potential closure or other costs associated with plants under construction, acquisition, disposition, and integration costs, earnings from Wholesale Gas Services, and one-time items related to corporate transactions (i.e. acquisitions and/or divestitures).

See **Appendix C: Business Unit Financial and Operational Goals** for specific business unit financial goals for each business unit.

### Business Unit Financial Performance Range

The business unit financial goal payout range for all participants is 0% to 200% of target based on actual performance achieved under the business unit financial goal. Results will be interpolated on a straight-line basis when they fall between performance levels.

See **Appendix C: Business Unit Financial and Operational Goals** for specific business unit financial goals for each business unit.

## Business Unit Operational Component

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### Business Unit Operational Goals

Operating company/business unit operational goals are key performance measures determined by each operating company/business unit. The key performance measures may include safety, culture, customer satisfaction, major projects, availability, reliability, or other applicable goals.

See **Appendix C: Business Unit Financial and Operational Goals** for specific operating company/business unit operational goals.

### Business Unit Operational Performance Range

The operating company/business unit operational goal payout range for all participants is 0% to 200% of target based on actual performance achieved under the operating company/business unit operational goal.

See **Appendix C: Business Unit Financial and Operational Goals** for specific operating company/business unit operational goals.

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## Individual Performance Component (grade 11 and above)

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### Individual Performance Goals

Individual performance is measured on goals set forth at the beginning of the year by the participant and his or her manager. Setting goals and rewarding individual achievements strengthen the link between pay and performance and drives accountability and recognition for individual performance.

### Individual Performance Achievement Range

Individual performance achievement can range from 0% to 200% of target based on achievement of individual goals and results from annual performance ratings. Management discretion is used to determine overall achievement of the individual performance component.

### Calibration of Individual Performance Achievement

Performance calibration helps to effectively differentiate high performers and reinforces the criteria for high performance across the organization. Individual performance achievement may be calibrated to ensure objective and consistent application of measuring standards of performance across the Southern Company system.

## Calculating the Target PPP Award and Actual PPP Payout

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### How Payouts are Determined

The target PPP award for each participant is determined as a percentage of Base Salary. The applicable percentage varies based on grade level within the Southern Company system's salary structure. To determine your individual PPP target level, refer to your Human Resources Business Consultant.

Payouts are calculated based on Base Salary as of December 31 of the performance period, except as described in **Appendix A: Additional Terms of Participation and Payout Eligibility**.

After the end of the performance period, the Committee reviews goal achievement. The results of the performance goals are added together to determine the overall PPP percentage achievement. The target award is then multiplied by the overall PPP percentage achievement to determine the total PPP payout.

### Committee Discretion

The Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts.

### Allocation of Overall PPP Payout

- At management discretion, a participant's PPP payout may be partially or fully reduced from the calculated PPP amount, including to zero.
  - At management discretion, a participant's PPP payout may be increased above the calculated PPP amount, but cannot exceed 200% of target.
  - Applicable tax rules require that the total calculated PPP payout for the applicable business unit/operating company must be paid out each year. Individual reductions must be reallocated among other participants within the applicable business unit/operating company.
  - PPP payout amounts cannot be transferred from one business unit/operating company to another business unit/operating company. However, this restriction does not impact individual employee transfers from one business unit/operating company to another.
-

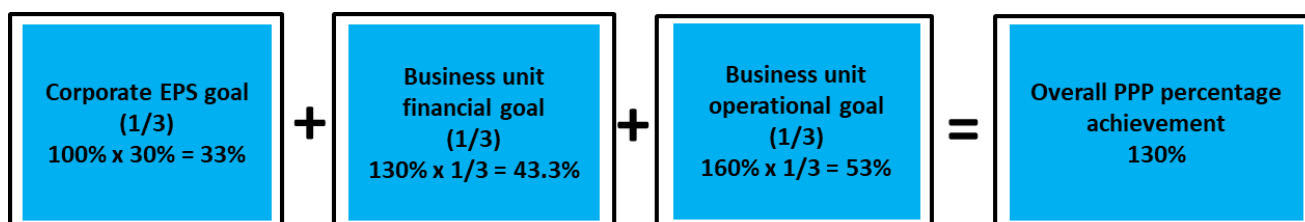
See **Appendix A: Additional Terms of Participation and Payout Eligibility** for more details about changes in employment status.

### PPP Payout Calculation Example

The following example assumes the EPS goal achievement was at 100% of target; the operating company/business unit financial goal achievement was at 130% of target; and the operational goal achievement was at 160% of target.

#### Example for a Participant without individual performance:

##### 1. Calculating the overall PPP percentage achievement:

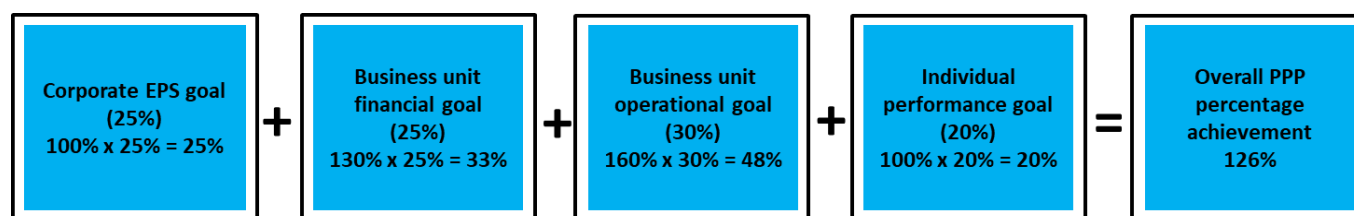


##### 2. Calculating the PPP payout using the target award % and overall PPP percentage achievement:

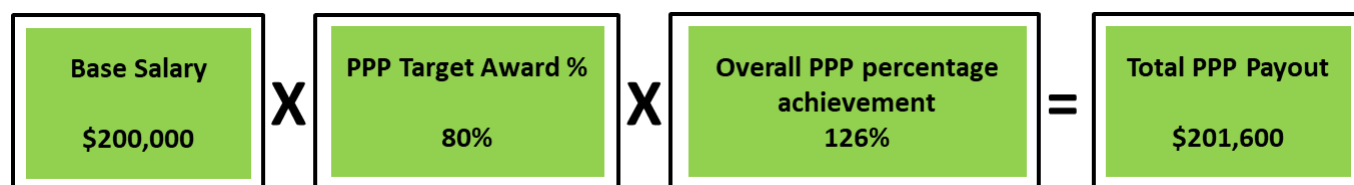


#### Example for a Participant with individual performance:

##### 1. Calculating the overall PPP percentage achievement



##### 2. Calculating the PPP payout using the target award % and overall PPP percentage achievement:



## Additional Terms of Participation and Payout Eligibility

### New Hires During Performance Period

Eligible participants will be entitled to receive a prorated payout.

### Change in Status During the Performance Period

- **Change in business unit or operating company** - Payout will be based on the overall PPP percentage achievement at each business unit or operating company and prorated using the number of full weeks at each business unit or operating company. If an employee transfers in or out of Southern Company Gas during the year, the final PPP payout will be prorated based on the time spent at each business unit, using the terms and conditions of each applicable plan (Southern Company Gas and Southern Company Classic). The employer at year-end will bear the cost of the combined PPP payout.
- **Promotion** – Payout will be prorated based upon the target award at each position held by the participant. The proration considers the number of full weeks at each target award.
- **Demotion** – Payout will be prorated based upon the target award of each position held by the participant. The proration considers the number of full weeks at each target award.
- **Participants that change their standard hours during the year** – Payout will be adjusted to reflect the weighted average standard hours during the year.

### Transfer or Job Change

FROM	TO	Impact to Payout
PPP-eligible position	PPP-ineligible covered position	No payout for the year of transfer.
PPP-eligible position	PPP-ineligible non-covered position	A prorated payout will be determined after the performance period using the Base Salary on the last day in the PPP eligible position. The proration considers the number of full weeks worked in the PPP eligible position.
PPP-eligible position	PPP-eligible position	Payout will be prorated based upon the target award of each position held by the participant using Base Salary on December 31. The proration considers the number of full weeks at each target award.
PPP-ineligible position	PPP-eligible position	A prorated payout will be determined after the performance period has ended using Base Salary on December 31. The proration considers the number of full weeks worked in the PPP-eligible position.

### Retirement

A prorated payout will be based on the overall PPP percentage achievement using Base Salary on date of retirement.

### Death

A prorated payout will be based on the overall PPP percentage achievement using Base Salary on date of death. Beneficiary designations are not accepted under the PPP; the payout will be paid to the participant's estate.

### Leave of Absence or Disability

- **Unpaid Leave of Absence or Disability** – If with pay at least one full month during the performance period, a prorated payout will be based on the overall PPP percentage achievement using Base Salary on last day before Leave of Absence or Disability began.
- **Paid Leave of Absence** – No impact.

## Military Leave of Absence

- **Qualified Military Leave of Absence per Active Duty Military Leave of Absence Policy** – Payout will be based on the overall PPP percentage achievement using Base Salary on last day before leave began. Payout will be for the full performance period and will not be prorated. Participant on qualified military leave will receive such payout during each year the participant is on qualified military leave but only if the participant would have received such payout if he or she had been actively employed (per the Active Duty Military Leave of Absence Policy). The Committee has the discretion to provide a reduced payout to a participant on military leave.
- **Temporary leave for military training and other types of inactive duty per Training and Inactive Duty Military Leave of Absence Policy** – PPP will be paid during military leave under the Inactive Duty Military Leave of Absence Policy if the participant would have been paid PPP had he or she been actively employed. If the participant is on leave at the time of payment, the PPP payout will be based on the overall PPP percentage achievement using Base Salary on the last day before training leave began.

## Other Voluntary or Involuntary Terminations

- **Terminations with severance pay (voluntary or involuntary)** – Any potential payout will be governed by the group or individual severance plan document.
- **Terminations for cause** – During the performance period or subsequent year prior to payout, a termination for cause will result in a complete forfeiture of the payout, including a vested payout. If it is subsequently determined that the participant was not terminated for cause, a payment may be made if approved by the participant's executive management and the General Counsel's office.
- **Terminated and rehired during the performance period** - Payout will be prorated based on the rehire date. The proration considers the number of full weeks worked during the performance period as of the rehire date.
- **Other voluntary or involuntary terminations prior to December 31** – No payout.

## Individual Performance Assessment after Termination of Employment

If a terminated employee is eligible for a PPP payout after termination of employment and is subject to the individual performance metric, management discretion is used to determine the overall achievement of the individual performance component.

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## Glossary of Terms

<b>Base Salary</b>	<p>Base Salary is defined as your annual base rate (excluding premiums, bonuses, overtime, shift differential and substitution pay) as of December 31 of the performance period, except in cases of change in employment status or PPP eligibility during the performance period.</p> <p>The base rate is not reduced by any of the following:</p> <ul style="list-style-type: none"> <li>• Taxes</li> <li>• Social Security</li> <li>• Amounts contributed on a participant's behalf to the flexible benefits plan or the Southern Company Employee Savings Plan (as an elective employer contribution per Section 4.1 therein)</li> <li>• Amounts the participant has deferred through the after-tax portion of the Southern Company Employee Savings Plan or through the Southern Company Deferred Compensation Plan</li> </ul>
<b>Disability</b>	Per the Omnibus Plan, Disability is defined under Southern Company's governing long-term disability plan or, if no such plan exists, at the discretion of the Committee.
<b>Funding</b>	<p>From a security viewpoint, this is an unfunded program. No assets are set aside in trust or otherwise to make payments under the PPP.</p> <p>From an accounting expense viewpoint, PPP is funded by each Southern Company subsidiary for the participants of that subsidiary. In general, if a participant is an employee of two companies during the performance period, the employer at year-end will bear the cost of that PPP payout.</p> <p>For financial statement purposes, the PPP is expensed at the full amount (determined under the formula) during the performance period for all participants except Southern Company Management Council members. It must be estimated quarterly, based on a good-faith estimate of results to date, and likely payouts. The quarterly expense is the pro rata expense for the year to date, less any amounts expensed in prior quarters. Conceivably, the expense for a quarter may be negative. PPP for Management Council members is expensed in the year it is paid.</p>
<b>Leave of Absence</b>	<p><b>Paid Leave of Absence</b> – includes maternity/parental, adoption and any FMLA certified as paid leave of absence.</p> <p><b>Unpaid Leave of Absence</b> – includes personal leave and any FMLA certified as unpaid leave</p>
<b>Proration</b>	<p>Prorated calculations are done on a weekly basis. The proration considers the number of full weeks worked during the performance period. Participants must be employed in an eligible position on Friday of a week to get credit for that week.</p> <p>For new hires, the proration considers the number of full weeks worked during the performance period. Participants must be in an eligible position on Friday of a week to get credit for that week.</p>
<b>Retirement</b>	Retirement is allowed retirement under the Southern Company Pension Plan.
<b>Termination for cause</b>	A termination for cause includes any type of termination (including, but not limited to, a voluntary or involuntary resignation by a participant, a voluntary or involuntary termination by the company, a termination with severance, a

## Attachment STF-L&amp;A-1-82c

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	<p>participant's retirement, or a participant's termination because of a disability) if such termination is related to cause.</p> <p>"Cause" includes, but is not limited to, the following:</p> <ul style="list-style-type: none"><li>• The final conviction of a felony or misdemeanor involving moral turpitude.</li><li>• Determined to have perpetrated any act involving fraud or dishonesty or breach of appropriate regulations of competent authorities.</li><li>• The carrying out of any activity or the making of any statement which would prejudice the good name and standing of Southern Company or subsidiary of Southern Company (collectively, the "Companies") or would bring the Companies into contempt or ridicule or would reasonably shock or offend any community in which the Companies are located.</li><li>• Violation of an applicable company drug and alcohol policy.</li><li>• In the event there is no drug and alcohol policy, attendance at work in a state of intoxication or otherwise being found in possession at workplace of any prohibited drug or substance, possession of which would amount to a criminal offense.</li><li>• Assault or other act of violence against any employee or other person during the course of employment.</li><li>• A material breach of the fiduciary obligations owed by an officer and an employee to the Companies</li><li>• Unsatisfactory performance of the duties and services required by the employee's employment.</li></ul>
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## Operational Goals - Additional Information

<b>Safety</b>	<p><b>Integration of Critical Risk Management (CRM) Focus Areas and Risk Reduction–</b> Assessment of progress related to the continued integration of CRM into standard processes and reducing overall risk scores. Risk reduction will occur and be measured through implementation of specific system, people based, and engineering controls in CRM risk areas.</p> <p><b>Safety &amp; Health Management System (SHMS)–</b> Measures the efforts of the continued development and implementation of the SHMS. Integrating the system is a multi-year with 2019 being the second phase of moving from a framework to an established system.</p> <p><b>Serious Injury Incident Rate (SIIR)–</b> Measures the number of serious injuries, as a percentage of the total workforce labor hours.</p>
<b>Customer Satisfaction (Electric)</b>	<p>The Customer Value Benchmark (CVB) Study measures customer feedback for the traditional electric operating companies (APC, GPC, and MPC) and peer utilities. The goal performance is determined by the quartile ranking for the results for Residential and General Business customer segments. Additionally, the Customer Satisfaction Operational Goal for the Managed Account Customers will be benchmarked against B2B Net Promoter Score (NPS) data from Satmetrix Systems, Inc. The total PPP goal payout for Customer Satisfaction will be an average of the payouts earned for the three customer groups. The payout for Southern Company and SCS groups is determined by the customer weighted average payout for each segment for APC, GPC and MPC.</p>
<b>Generation Peak Season EFOR</b>	<p>Peak Season EFOR measures the percent of scheduled operating time a generating unit is offline or unable to reach full capability due to forced outages or equipment failures. A lower number is better because when EFOR increases, fewer units are available, making it necessary to run higher-cost units or buy energy at a greater cost to customers. EFOR is measured during the Peak Season months, including January, February, June, July, and August.</p>
<b>Nuclear Operations</b>	<p>Measures are focused on Nuclear Safety and Nuclear Reliability, including the INPO Index, NRC Reactor Oversight Process (ROP), and Annual Capability Factor.</p>
<b>Transmission and Distribution Reliability</b>	<p>Measures the frequency (SAIFI) and duration (SAIDI) of outages for Transmission and Distribution.</p>
<b>Overall Satisfaction</b>	<p>A component of <u>GAS Customer Satisfaction</u>. The GAS Overall Satisfaction metric is a subset of the data collected via the Customer Experience Transaction Survey. The Customer Experience Transaction Survey is a transaction survey (implemented by GAS in 2015) on customer interactions in regulated markets. In 2019, the survey is expanded to include the Atlanta Gas Light market in Georgia. The result is defined as the combined percentage of customer ratings for customer care (customer service representatives - CSR) and the field (field service representatives - FSR) in the top two boxes of the customer satisfaction transaction survey.</p>
<b>Miles of Main Replaced</b>	<p>A component of <u>GAS Operations</u>. Measures the miles of main installed under the Rider programs within the various jurisdictions in which we operate.</p>
<b>Damage Ratio</b>	<p>A component of <u>GAS Operations</u>. Total Damage Ratio measures damages to infrastructure due to improper locating or poor 1st, 2nd, or 3rd party excavation practices. It is defined as the total number of excavation damages divided by the number of locate tickets times 1000.</p>



## Attachment STF-L&amp;A-1-82c

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<b>Leak Response &gt; 60 Minutes</b>	A component of <u>GAS Operations</u> . Measures the percentage of leaks that were responded to in greater than 60 minutes, adjusted for anomalous weather or airborne odor events.
<b>Major Projects – Vogtle 3 &amp; 4 Assessment</b>	Georgia Power and Southern Nuclear are committed to safe, quality and compliant construction of Vogtle 3 & 4, excellence in transition to operations, and prudent decision making to support investment recovery. Performance is assessed by the Vogtle Executive Oversight Committee and approved by the Southern Company CEO and confirmed by the Operations, Environmental and Safety Committee of the Southern Company Board of Directors.
<b>Culture</b>	<p><b>Representation Assessment</b> – Subjective assessment of each business unit’s improvement in workforce representation, and promotions, focusing on opportunities for minority and female employees. The assessment is reviewed by the Southern Company CEO, the SVP Human Resources, and/or Executive Leader in each business unit in coordination with the Southern Company Office of Diversity and Inclusion. The final assessment is approved by the Southern Company CEO.</p> <p><b>Inclusiveness Index</b> – Measures Southern Company’s percentile rank on the DiversityInc Top 50 Companies for Diversity Survey. This goal also measures Southern Company’s inclusion in any of the Diversity Inc. Specialty Lists, the Military Friendly Employer list, Black Enterprise Magazine’s Top Companies for Diversity list, and achieving at least 90% on Human Rights Campaign’s Corporate Equality Index and the Disability Equality Index.</p> <p><b>Supplier Diversity</b> - SoCo Electric measures the percentage of eligible spend with minority-owned and women-owned businesses (first tier suppliers). SoCo Gas measures the percentage of eligible spend with minority-owned, women-owned, and veteran-owned businesses (first tier suppliers) and prime contractor spend with minority-owned, women-owned, and veteran-owned subcontractors (second tier suppliers).</p>



2019 Georgia Power PPP Goals						
Southern Company EPS Goal (1/3 weight)						
Southern Company EPS		0%	EPS Guidance Range			200%
		\$2.890	\$2.980	\$3.040	\$3.100	\$3.190
Business Unit Financial Goal (1/3 weight)						
GPC Net Income (\$ millions)		0%	50%	100%	175%	200%
		\$1,443.0	\$1,513.5	\$1,584.0	\$1,690.0	\$1,740.0
Operational Goals (1/3 weight)						
(Operational Goal weight)		0%	100%	200%		
Safety (20%)	Integration of CRM Focus Areas and Risk Reduction (7%)		Assessment of Integration of CRM Focus Areas and Risk Reduction			
	Safety & Health Management System (5%)		Assessment of continued development and implementation of the SHMS			
	Serious Injury Incident Rate (8%)		0.11	0.09	0.08	
Operations (50%)	Customer Satisfaction (30%)		Bottom Quartile on Residential and General Business CVB; Managed Accounts NPS score at 9 or below	2nd Quartile on Residential and General Business CVB (125%); Managed Accounts NPS score at 30-40	Top Quartile on Residential and General Business CVB; Managed Accounts NPS score at 51-100	
	Generation Peak Season EFOR (10%)		6.00%	5.00%	2.00%	
	Transmission Reliability (5%)	SAIDI (Duration - 2.5%)	10.2	7.8	7.0	
		SAIFI (Frequency - 2.5%)	0.171	0.131	0.118	
	Distribution Reliability (5%)	SAIDI (Duration - 2.5%)	147.5	113.4	102.1	
		SAIFI (Frequency - 2.5%)	1.561	1.201	1.081	
Major Projects (20%)	Plant Vogtle Units 3 & 4 (20%)		Performance is assessed by the Vogtle Executive Oversight Committee and approved by the Southern Company CEO and confirmed by the Operations, Environmental and Safety Committee of the Southern Company Board of Directors.			
Culture (10%)	Representation (7.0%)		Assessment by the Southern Company CEO and Management Council			
	Work Environment (1.5%)	DiversityInc Ranking (0.75%)	Median	Top Quartile	Top Decile	
		DiversityInc Specialty List (0.75%)	Inclusion on 1 list	Inclusion on 2 lists	Inclusion on 4 lists	
		Supplier Diversity (1.5%)	% of Spend	10.59%	20.50%	24.60%

Southern Company EPS and Business Unit Financial goals exclude potential charges associated with construction projects, acquisition, disposition and integration impacts, including the preliminary gain of approximately \$1.28 per share for the sale of Gulf Power, and earnings from Wholesale Gas Services.

Goal performance will be measured and governed according to goal specifications maintained by SCS Corporate Performance.

## Georgia Power Company

### Incentive Compensation Costs

	Period Ending			
	7/31/2020	12/31/2020	12/31/2021	12/31/2022
<u>Performance Pay Program (PPP)</u>				
GPC - directly-incurred	\$ 81,721,860	\$ 82,736,454	\$ 85,213,578	\$ 87,764,607
SCS - allocated costs to GPC	42,968,684	44,035,413	44,481,292	45,255,728
SNC - allocated costs to GPC	37,167,377	37,935,446	39,319,584	39,207,660
	<u>\$ 161,857,921</u>	<u>\$ 164,707,313</u>	<u>\$ 169,014,455</u>	<u>\$ 172,227,995</u>
 <u>Long-term Performance Pay (See Note 1 below)</u>				
GPC - directly-incurred	\$ 11,047,650	\$ 11,188,203	\$ 11,943,753	\$ 12,270,087
SCS - allocated to GPC	9,677,477	9,510,458	11,328,767	11,587,008
SNC - allocated to GPC	4,385,968	4,187,659	4,275,496	4,375,638
	<u>\$ 25,111,096</u>	<u>\$ 24,886,320</u>	<u>\$ 27,548,016</u>	<u>\$ 28,232,732</u>
 GPC - directly-incurred - (Net)	\$ 92,769,510	\$ 93,924,657	\$ 97,157,331	\$ 100,034,694
<b>O&amp;M Portion (see Attachment STF-L&amp;A-1-84a)</b>	<b>60,642,639</b>	<b>61,354,910</b>	<b>63,454,149</b>	<b>65,287,139</b>
<b>O&amp;M Expense Ratio</b>	<b>65%</b>	<b>65%</b>	<b>65%</b>	<b>65%</b>
 SCS Incentives billed (Total 100%)	\$ 52,646,162	\$ 53,545,871	\$ 55,810,060	\$ 56,842,735
<b>O&amp;M Portion (see Attachment STF-L&amp;A-1-83b)</b>	<b>31,295,973</b>	<b>31,734,392</b>	<b>33,754,738</b>	<b>34,691,940</b>
<b>O&amp;M Expense Ratio</b>	<b>59%</b>	<b>59%</b>	<b>60%</b>	<b>61%</b>
 SNC Incentives billed (Total 100%)	\$ 41,553,345	\$ 42,123,105	\$ 43,595,080	\$ 43,583,297
<b>O&amp;M Portion (see Attachment STF-L&amp;A-1-83a)</b>	<b>28,333,111</b>	<b>28,691,429</b>	<b>30,873,847</b>	<b>39,244,271</b>
<b>O&amp;M Expense Ratio</b>	<b>68%</b>	<b>68%</b>	<b>71%</b>	<b>90%</b>
 <b>TOTAL O&amp;M PORTION</b>	<b>\$ 120,271,723</b>	<b>\$ 121,780,731</b>	<b>\$ 128,082,734</b>	<b>\$ 139,223,350</b>

### Note 1 - Long-term Performance Pay Programs:

#### Performance Share Program (included in Long-term above)

GPC - directly-incurred	\$ 8,044,703	\$ 8,156,769	\$ 8,791,991	\$ 9,055,753
SCS - allocated to GPC	7,026,664	6,957,751	8,662,393	8,861,049
SNC - allocated to GPC	3,128,949	2,994,967	3,113,549	3,203,245
	<u>\$ 18,200,316</u>	<u>\$ 18,109,487</u>	<u>\$ 20,567,933</u>	<u>\$ 21,120,047</u>

#### Restricted Stock Program (included in Long-term above)

GPC - directly-incurred	\$ 3,002,947	\$ 3,031,434	\$ 3,151,762	\$ 3,214,334
SCS - allocated to GPC	2,650,814	2,552,707	2,666,375	2,725,958
SNC - allocated to GPC	1,257,018	1,192,692	1,161,947	1,172,393
	<u>\$ 6,910,779</u>	<u>\$ 6,776,833</u>	<u>\$ 6,980,084</u>	<u>\$ 7,112,685</u>

EXHIBIT\_\_(RS/RT-29)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-1**

**STF-L&A-1-39**

Question:

With regard to the Company's storm damage reserves, storm damage accruals, and storm damage expenses, please provide the following information:

- a. In the same format as per the response to STF-RCS-1-28 in Docket No. 36989, please provide (1) the storm damage reserve beginning balance, (2) the annual storm damage expense accrual, (3) actual storm damage charges to the reserve, and (4) the resulting storm damage reserve ending balance for each of the years 2013 through 2018 and for 2019 as of June 30.
- b. The storm damage accrual and average storm damage reserve balance for the forecasted test year, including a workpaper showing the derivation of these dollar amounts.

Response:

- a. Please see Attachment STF-L&A-1-39a.
- b. Please see Attachment STF-L&A-1-39b.

**GEORGIA POWER COMPANY**  
**MONTHLY STORM DAMAGE ACCRUAL, CHARGES, AND REGULATORY ASSET BALANCE**  
**(AMOUNTS IN THOUSANDS)**

Month	Beg. Balance	Accrual	Charges	Ending Balance
Jan-13	\$ 38,193	\$ (1,511)	\$ 581	\$ 37,262
Feb-13	37,262	(1,511)	1,971	37,722
Mar-13	37,722	(1,511)	2,284	38,495
Apr-13	38,495	(1,511)	1,380	38,364
May-13	38,364	(1,511)	1,615	38,467
Jun-13	38,467	(1,511)	5,457	42,413
Jul-13	42,413	(1,511)	2,666	43,567
Aug-13	43,567	(1,511)	201	42,257
Sep-13	42,257	(1,511)	832	41,579
Oct-13	41,579	(1,511)	(439)	39,628
Nov-13	39,628	(1,511)	119	38,236
Dec-13	38,236	(1,511)	335	37,060
	\$	(18,134)	\$	17,001

Month	Beg. Balance	Accrual	Charges	Ending Balance
Jan-14	\$ 37,060	\$ (2,493)	\$ 3,120	\$ 37,687
Feb-14	37,687	(2,493)	16,921	52,115
Mar-14	52,115	(2,493)	60,680	110,303
Apr-14	110,303	(2,493)	(10,543)	97,267
May-14	97,267	(2,493)	6,552	101,327
Jun-14	101,327	(2,493)	7,963	106,797
Jul-14	106,797	(2,493)	2,291	106,596
Aug-14	106,596	(2,493)	1,614	105,717
Sep-14	105,717	(2,493)	1,391	104,616
Oct-14	104,616	(2,493)	1	102,124
Nov-14	102,124	(2,493)	712	100,343
Dec-14	100,343	(2,493)	239	98,089
	\$	(29,914)	\$	90,942

Month	Beg. Balance	Accrual	Charges	Ending Balance
Jan-15	\$ 98,089	\$ (2,493)	\$ 504	\$ 96,100
Feb-15	96,100	(2,493)	4,347	97,953
Mar-15	97,953	(2,493)	7,050	102,510
Apr-15	102,510	(2,493)	1,430	101,447
May-15	101,447	(2,493)	1,538	100,493
Jun-15	100,493	(2,493)	2,033	100,033
Jul-15	100,033	(2,493)	2,611	100,151
Aug-15	100,151	(2,493)	1,548	99,205
Sep-15	99,205	(2,493)	602	97,314
Oct-15	97,314	(2,493)	661	95,482
Nov-15	95,482	(2,493)	1,007	93,996
Dec-15	93,996	(2,493)	158	91,661
	\$	(29,914)	\$	23,487

Month	Beg. Balance	Accrual	Charges	Ending Balance
Jan-16	\$ 91,661	\$ (2,493)	\$ 2,729	\$ 91,897
Feb-16	91,897	(2,493)	2,357	91,761
Mar-16	91,761	(2,493)	916	90,184
Apr-16	90,184	(2,493)	157	87,848
May-16	87,848	(2,493)	1,269	86,624
Jun-16	86,624	(2,493)	1,578	85,709
Jul-16	85,709	(2,493)	4,503	87,720
Aug-16	87,720	(2,493)	1,020	86,247
Sep-16	86,247	(2,493)	10,033	93,786
Oct-16	93,786	(2,493)	46,756	138,049
Nov-16	138,049	(2,493)	43,503	179,059
Dec-16	179,059	(2,493)	29,650	206,216
	\$	(29,914)	\$	144,469

Month	Beg. Balance	Accrual	Charges	Ending Balance
Jan-17	\$ 206,216	\$ (2,493)	\$ 10,316	\$ 214,040
Feb-17	214,040	(2,493)	6,711	218,258
Mar-17	218,258	(2,493)	3,367	219,132
Apr-17	219,132	(2,493)	4,803	221,442
May-17	221,442	(2,493)	386	219,335
Jun-17	219,335	(2,493)	2,160	219,003
Jul-17	219,003	(2,493)	(1,157)	215,353
Aug-17	215,353	(2,493)	792	213,652
Sep-17	213,652	(2,493)	149,191	360,351
Oct-17	360,351	(2,493)	(4,278)	353,580
Nov-17	353,580	(2,493)	(3,831)	347,255
Dec-17	347,255	(2,493)	(11,654)	333,109
	\$	(29,914)	\$	156,806

Month	Beg. Balance	Accrual	Charges	Ending Balance
Jan-18	\$ 333,109	\$ (2,493)	\$ 1,121	\$ 331,737
Feb-18	331,737	(2,493)	(7,415)	321,830
Mar-18	321,830	(2,493)	(1,021)	318,316
Apr-18	318,316	(2,493)	1,831	317,653
May-18	317,653	(2,493)	(480)	314,681
Jun-18	314,681	(2,493)	381	312,569
Jul-18	312,569	(2,493)	3,089	313,165
Aug-18	313,165	(2,493)	1,691	312,364
Sep-18	312,364	(2,493)	660	310,531
Oct-18	310,531	(2,493)	124,060	432,098
Nov-18	432,098	(2,493)	936	430,541
Dec-18	430,541	(2,493)	(12,263)	415,786
	\$	(29,914)	\$	112,591

Month	Beg. Balance	Accrual	Charges	Ending Balance
Jan-19	\$ 415,786	\$ (2,493)	\$ (3,695)	\$ 409,598
Feb-19	409,598	(2,493)	14,581	421,686
Mar-19	421,686	(2,493)	3,443	422,636
Apr-19	422,636	(2,493)	7,404	427,547
May-19	427,547	(2,493)	(4,593)	420,461
Jun-19	420,461	(2,493)	1,710	419,679
	\$	(14,957)	\$	18,850

Note: Details may not add to totals due to rounding.

**GEORGIA POWER COMPANY**  
**BUDGETED MONTHLY STORM DAMAGE ACCRUAL,**  
**CHARGES, AND REGULATORY ASSET BALANCE**  
**(AMOUNTS IN THOUSANDS)**

*January 2019 - July 2020 Per Budget*

Month	Beg. Balance (a)	Accrual (b)	Charges (c)	Ending Balance
Jan-19	\$ 415,786	\$ (2,493)	\$ 5,294	\$ 418,587
Feb-19	418,587	(2,493)	5,294	421,388
Mar-19	421,388	(2,493)	5,294	424,189
Apr-19	424,189	(2,493)	5,294	426,990
May-19	426,990	(2,493)	5,294	429,792
Jun-19	429,792	(2,493)	5,294	432,593
Jul-19	432,593	(2,493)	5,294	435,394
Aug-19	435,394	(2,493)	5,294	438,195
Sep-19	438,195	(2,493)	5,294	440,996
Oct-19	440,996	(2,493)	5,294	443,798
Nov-19	443,798	(2,493)	5,294	446,599
Dec-19	446,599	(2,493)	5,294	449,400
Jan-20	449,400	(17,777)	5,294	436,917
Feb-20	436,917	(17,777)	5,294	424,433
Mar-20	424,433	(17,777)	5,294	411,950
Apr-20	411,950	(17,777)	5,294	399,467
May-20	399,467	(17,777)	5,294	386,983
Jun-20	386,983	(17,777)	5,294	374,500
Jul-20	374,500	(17,777)	5,294	362,017

Test Period Accrual	\$	(136,906)
Test Period Regulatory Asset 13-Month Average	\$	419,281

*Normalized Test Period (d)*

Month	Beg. Balance	Accrual	Charges (c)	Ending Balance
Aug-19	\$ 435,394	\$ (17,777)	\$ 5,294	\$ 422,911
Sep-19	422,911	(17,777)	5,294	410,427
Oct-19	410,427	(17,777)	5,294	397,944
Nov-19	397,944	(17,777)	5,294	385,461
Dec-19	385,461	(17,777)	5,294	372,977
Jan-20	372,977	(17,777)	5,294	360,494
Feb-20	360,494	(17,777)	5,294	348,011
Mar-20	348,011	(17,777)	5,294	335,527
Apr-20	335,527	(17,777)	5,294	323,044
May-20	323,044	(17,777)	5,294	310,561
Jun-20	310,561	(17,777)	5,294	298,077
Jul-20	298,077	(17,777)	5,294	285,594
		\$ (213,328)	\$ 63,528	

Test Period Accrual	\$	(213,328)
Test Period Regulatory Asset 13-Month Average	\$	360,494

Note: Details may not add to totals due to rounding.

- (a) January 2019 beginning balance from Attachment STF-L&A-1-39a (December 2018 ending balance)
- (b) Budget reflects proposed accrual beginning January 2020 as calculated on Exhibit \_\_ (DPP/SPA/MBR-5, Schedule 2)
- (c) Budget reflects 10-year average charges as calculated on Exhibit \_\_ (DPP/SPA/MBR-5, Schedule 2)
- (d) Test period normalized to reflect proposed annual accrual; reference FOOTNOTES/AP and BU/ in Exhibit \_\_ (DPP/SPA/MBR-2)

EXHIBIT\_\_(RS/RT-30)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-10**

**STF-PIA-10-3**

Question:

Please identify the amount of bad debt expense (in dollars) in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 4 and the line item(s) where the bad debt expense is recorded.

Response:

The Company's projected bad debt expense for the test year of \$13.445 million is recorded in Exhibit \_\_ (DPP/SPA/MBR, Schedule 1 Total Company) Page 4, line 14 "Customer Accounting".



**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-10**

**STF-PIA-10-4**

Question:

Please identify the amount of bad debt expense (in dollars) in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 6 and the line item(s) where the bad debt expense is recorded.

Response:

The Company's projected bad debt expense for the calendar year 2020 of \$14.003 million is recorded in Exhibit \_\_ (DPP/SPA/MBR, Schedule 1 Total Company) Page 6, line 14 "Customer Accounting".

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-10**

**STF-PIA-10-5**

Question:

Please identify the amount of bad debt expense (in dollars) in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 8 and the line item(s) where the bad debt expense is recorded.

Response:

The Company's projected bad debt expense for the calendar year 2021 of \$14.003 million is recorded in Exhibit \_\_ (DPP/SPA/MBR, Schedule 1 Total Company) Page 8, line 14 "Customer Accounting".

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-10**

**STF-PIA-10-6**

Question:

Please identify the amount of bad debt expense (in dollars) in Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 1 Total Company) Page 10 and the line item(s) where the bad debt expense is recorded.

Response:

The Company's projected bad debt expense for the calendar year 2022 of \$14.004 million is recorded in Exhibit \_\_ (DPP/SPA/MBR, Schedule 1 Total Company) Page 10, line 14 "Customer Accounting".

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-10**

**STF-PIA-10-7**

Question:

Please identify the amount of bad debt expense (in dollars) in 2016 ASR Section 2 Page 2 "Operating Income" statement and the line item(s) where the bad debt expense is recorded.

Response:

The Company's bad debt expense of \$14.476 million is recorded in the 2016 ASR Section 2, Page 2, under "Operating Expenses" in line item "Customer Accounting".

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-10**

**STF-PIA-10-8**

Question:

Please identify the amount of bad debt expense (in dollars) in 2017 ASR Section 2 Page 2 "Operating Income" statement and the line item(s) where the bad debt expense is recorded.

Response:

The Company's bad debt expense of \$11.250 million is recorded in the 2017 ASR Section 2, Page 2, under "Operating Expenses" in line item "Customer Accounting".

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-10**

**STF-PIA-10-9**

Question:

Please identify the amount of bad debt expense (in dollars) in 2018 Amended ASR Section 2 Page 2 "Operating Income" statement and the line item(s) where the bad debt expense is recorded.

Response:

The Company's bad debt expense of \$11.923 million is recorded in the 2018 Amended ASR Section 2, Page 2, under "Operating Expenses" in line item "Customer Accounting".

EXHIBIT\_\_(RS/RT-31)

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-13**

**STF-PIA-13-3**

Question:

Please refer to the response to STF-PIA-4-10: Please explain why the Carrying Costs on the DSM Under Recovery decreases in 2021 and 2022 while the projected Under recovery balance remains the same. Please provide the calculation for the carrying cost for the Test Period, 2020, 2021, and 2022.

Response:

The line "Projected Residential Under/(Over) Recovery 12/31/19" in Attachment STF-PIA-4-10 is not a balance; rather, it reflects the annual recovery of the balance as of December 31, 2019 of approximately \$13 million, which the Company proposes to recover evenly over a 3-year period ending December 2022.

Please see Attachment STF-PIA-13-3 for the carrying cost for the Test Period, 2020, 2021, and 2022.



### Test Period Carrying Cost Calculation

[illegible][illegible]

### Carrying Cost Calculation

[illegible]

### Carrying Cost Calculation

[illegible]

### Carrying Cost Calculation

	Beg	Pri	Sec	Tert	Quar	Fifth	Sixth	Seventh	Eighth	Ninth	Tenth	Eleventh	Twelfth	Total
Beg Pre-Tax Balance	\$ (2,462,193)	\$ (1,760,711)	\$ (1,126,923)	\$ (695,424)	\$ (1,313,775)	\$ (951,391)	\$ (793,890)	\$ (194,809)	\$ 402,862	\$ 829,124	\$ 891,728	\$ (743,580)		
ADITs	622,836	445,389	285,066	175,914	332,433	270,714	200,822	49,279	(101,908)	(209,638)	(225,572)	188,096		
Beg Net-Tax Balance	\$ (1,839,356)	\$ (1,315,321)	\$ (841,857)	\$ (519,509)	\$ (981,443)	\$ (710,876)	\$ (593,068)	\$ (145,530)	\$ 300,954	\$ 619,389	\$ 666,157	\$ (555,484)		
Annual Revenue Requirement Rate	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%		
Annual Carrying Cost	\$ (186,943)	\$ (133,683)	\$ (85,562)	\$ (52,800)	\$ (99,749)	\$ (72,250)	\$ (60,276)	\$ (14,791)	\$ 30,387	\$ 62,952	\$ 67,705	\$ (56,457)		
Number of Days in Year	365	365	365	365	365	365	365	365	365	365	365	365		
Daily Carrying Cost	\$ (512)	\$ (366)	\$ (234)	\$ (145)	\$ (273)	\$ (198)	\$ (165)	\$ (41)	\$ 84	\$ 172	\$ 185	\$ (155)		
Number of Days in Month	31	28	31	31	31	30	31	31	31	30	31	31		
Current Month Carrying Cost	\$ (15,877)	\$ (10,255)	\$ (7,267)	\$ (4,340)	\$ (8,472)	\$ (5,938)	\$ (5,119)	\$ (1,256)	\$ 2,514	\$ 5,347	\$ 5,565	\$ (4,795)		\$ (49,893)

### Carrying Cost Calculation

[illegible]

EXHIBIT\_\_(RS/RT-32)

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NO. 42516**

**Data Request No. STF-PIA-14-4**

**BASIS FOR THE ASSERTION THAT THE  
INFORMATION SUBMITTED IS TRADE SECRET**

As part of Georgia Power Company's 2019 Rate Case filed in Docket No. 42516, Georgia Power Company (the "Company") submits to the Georgia Public Service Commission (the "Commission") its response to STF-PIA-14-4 ("Response"). In the Response, the Company has provided detailed information regarding the costs and associated contingency incurred in preparation for expenditures for ash pond closures. Portions of such information (the "Information") constitute trade secret information of the Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details on the costs and associated contingency incurred in preparation for ash pond closure efforts to comply with Coal Combustion Residuals ("CCR") Rule closure requirements. Publicly disclosing this information would allow bidders in future solicitations to tailor their proposals and potentially set an artificial floor on bidding, which would harm customers by not allowing the Company to conduct a proper solicitation and obtain the best cost estimates for future consulting work.

The trade secret portions of the Information are subject to substantial procedures to maintain its secrecy. Only select Company and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-PIA-14**

**STF-PIA-14-4**

Question:

Refer to the Company Exhibit \_\_ (DPP-SPA-MBR-1, Schedule 2 Traditional Base), Page 5 of 5.

If all contingency were removed from the Company's CCR ARO compliance estimate, how would the annual CCR ARO recovery amounts and the revenue requirement amounts change? Explain fully and identify the annual recovery and revenue requirement amounts that would be produced by eliminating CCR ARO contingency from Exhibit \_\_ (DPP-SPA-MBR-1, Schedule 2 Traditional Base). Include supporting calculations.

Response:

Please see Attachment STF-PIA-14-4 for the annual recovery and revenue requirement amounts that would be produced by eliminating CCR ARO contingency from Exhibit \_\_ (DPP/SPA/MBR-1, Schedule 2 Traditional Base Errata).

## PUBLIC DISCLOSURE

**GEORGIA POWER COMPANY**

**COAL COMBUSTION RESIDUAL (CCR) - ASSET RETIREMENT OBLIGATION (ARO) COMPLIANCE**  
**FOR THE TWELVE MONTH PERIODS ENDING JULY 31, 2020 AND DECEMBER 31, 2020-2022**  
**(AMOUNTS IN THOUSANDS)**

**Errata**

Description	Test Period	2020	2021	2022
<b>CCR ARO Compliance Expenditures</b>	\$ 245,214	\$ 276,899	\$ 395,097	\$ 655,083
Amortization of Prior Under Recovery		\$ 80,360	\$ 80,360	\$ 80,360
1/3 Recovery of 2020 Expenditures		92,300	92,300	92,300
1/3 Recovery of 2021 Expenditures			131,699	131,699
1/3 Recovery of 2022 Expenditures				218,361
<b>CCR ARO Compliance Recovery</b>	\$ 172,668	\$ 172,660	\$ 304,359	\$ 522,720
<b>Revenue Requirement</b>	<b>\$ 151,267</b>	<b>\$ 158,073</b>	<b>\$ 297,559</b>	<b>\$ 524,905</b>

**Impact of Removing CCR ARO Contingency from Compliance Estimate**

Description	Test Period	2020	2021	2022
<b>CCR ARO Compliance Expenditures</b>	REDACTED	REDACTED	REDACTED	REDACTED
Amortization of Prior Under Recovery	REDACTED	REDACTED	REDACTED	REDACTED
1/3 Recovery of 2020 Expenditures	REDACTED	REDACTED	REDACTED	REDACTED
1/3 Recovery of 2021 Expenditures			REDACTED	REDACTED
1/3 Recovery of 2022 Expenditures				REDACTED
<b>CCR ARO Compliance Recovery</b>	REDACTED	REDACTED	REDACTED	REDACTED
<b>Revenue Requirement</b>	REDACTED	REDACTED	REDACTED	REDACTED

**Difference**

Description	Test Period	2020	2021	2022
<b>CCR ARO Compliance Expenditures</b>	REDACTED	REDACTED	REDACTED	REDACTED
Amortization of Prior Under Recovery	REDACTED	REDACTED	REDACTED	REDACTED
1/3 Recovery of 2020 Expenditures	REDACTED	REDACTED	REDACTED	REDACTED
1/3 Recovery of 2021 Expenditures			REDACTED	REDACTED
1/3 Recovery of 2022 Expenditures				REDACTED
<b>CCR ARO Compliance Recovery</b>	REDACTED	REDACTED	REDACTED	REDACTED
<b>Revenue Requirement</b>	<b>REDACTED</b>	<b>REDACTED</b>	<b>REDACTED</b>	<b>REDACTED</b>

**GEORGIA POWER COMPANY****COAL COMBUSTION RESIDUAL (CCR) - ASSET RETIREMENT OBLIGATION (ARO) COMPLIANCE**  
**FOR THE TWELVE MONTH PERIODS ENDING JULY 31, 2020 AND DECEMBER 31, 2020-2022**  
**(AMOUNTS IN THOUSANDS)****Without Contingency**

Description	Test Period	2020	2021	2022
<b>CCR ARO Compliance Regulatory Asset - Beginning Balance</b>		REDACTED	REDACTED	REDACTED
<b>CCR ARO Compliance Expenditures</b>	REDACTED	REDACTED	REDACTED	REDACTED
Amortization of Prior Under Recovery		REDACTED	REDACTED	REDACTED
1/3 Recovery of 2020 Expenditures		REDACTED	REDACTED	REDACTED
1/3 Recovery of 2021 Expenditures			REDACTED	REDACTED
1/3 Recovery of 2022 Expenditures				REDACTED
<b>CCR ARO Compliance Recovery</b>	REDACTED	REDACTED	REDACTED	REDACTED
<b>CCR ARO Compliance Regulatory Asset - Ending Balance</b>		REDACTED	REDACTED	REDACTED
CCR ARO Compliance Regulatory Asset (13-Month average)	REDACTED	REDACTED	REDACTED	REDACTED
Accumulated Deferred Income Taxes	REDACTED	REDACTED	REDACTED	REDACTED
<b>CCR ARO Compliance Retail Rate Base</b>	REDACTED	REDACTED	REDACTED	REDACTED
<b>Operating Income Deficiency</b>				
CCR ARO Compliance Revenues Included in Current Rates	REDACTED	REDACTED	REDACTED	REDACTED
CCR ARO Compliance Recovery	REDACTED	REDACTED	REDACTED	REDACTED
Earnings Before Taxes	REDACTED	REDACTED	REDACTED	REDACTED
Federal Income Taxes	REDACTED	REDACTED	REDACTED	REDACTED
State Income Taxes	REDACTED	REDACTED	REDACTED	REDACTED
<b>Operating Income Deficiency</b>	REDACTED	REDACTED	REDACTED	REDACTED
 CCR ARO Compliance Retail Rate Base	 REDACTED	 REDACTED	 REDACTED	 REDACTED
Requested Rate of Return	× 7.93%	7.98%	8.07%	8.13%
Earnings Requirement	REDACTED	REDACTED	REDACTED	REDACTED
Less: Operating Income Deficiency	- REDACTED	REDACTED	REDACTED	REDACTED
Earnings Deficiency	REDACTED	REDACTED	REDACTED	REDACTED
Income Expansion Factor	÷ 74.602%	74.596%	74.597%	74.598%
<b>CCR ARO Compliance Revenue Requirement</b>	<u>REDACTED</u>	<u>REDACTED</u>	<u>REDACTED</u>	<u>REDACTED</u>
<b>CCR ARO Compliance Incremental Increase</b>		<u>REDACTED</u>	<u>REDACTED</u>	<u>REDACTED</u>

Note: Details may not add to totals due to rounding.

EXHIBIT\_\_(RS/RT-33)



**GEORGIA POWER COMPANY**  
**Docket No. 42516**  
**Georgia Power Company's 2019 Rate Case**  
**Staff Data Request No. STF-L&A-11**

**STF-L&A-11-1**

Question:

Does Georgia Power have any General Accounting Procedures (GAP) beyond GAP 58?

- a. List and provide GAP 58 and any updates, addendums or additional GAPs beyond GAP 58.

Response:

Below is a list of the current Georgia Power General Accounting Procedures (GAP).

<b>General Accounting Procedure</b>
GAP 52 – Non-Electric Services Business
GAP 53 – Accounting for Research Development Projects
GAP 54 – Procurement Methods and Payment Approvals
GAP 55 – Work Orders
GAP 58 – Accounting for Work Performed on Behalf of Other Companies
GAP 60 – Fleet Usage and Expense Reporting
GAP 61 – Accounting for Company Materials
GAP 63 – Office Furniture and Equipment
GAP 68 – Leases
GAP 69 – Excess Facility Charge
GAP 71 – Taxable Awards
GAP 73 – Approval Limits
GAP 74 – Undistributed Liabilities
GAP 75 – Per Diem
GAP 76 – Employees Receiving Checks
GAP 77 – Capital Budget
GAP 80 – Municipal Franchise Agreements
GAP 411 – Telecommunication Devices
GAP 426 – Below the Line Expenses

Please see Attachment STF-L&A-11-1 for current copies of the Company's GAPs. Due to its voluminous nature, this information is being provided in electronic format only.

*(Note: Employee names and contact information were removed from the documents.)*



**Georgia Power Company**

**General Accounting Procedure 58**

**Accounting for Work Performed on behalf  
of Other Companies**



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## 1.0 Purpose

The purpose of this procedure is to provide Company policies, guidelines and general instructions for reporting and billing expenses to associated operating companies and non-associated companies.

### 1.1 Policy

The Company may provide available employees and other resources to associated operating companies, non-associated utility companies and other businesses, and will recover all appropriate costs associated with providing these resources. Employees that receive requests for services should contact his/her supervisor or Department Manager prior to providing the service. Under no circumstances will requests received from other companies take priority over Company work.

It is the responsibility of the region, plant or department management where the services are initiated to ensure that all reimbursable expenses are charged to an assigned EWO and FERCSUB. Failure to capture these expenses could result in a financial loss to the Company.

Note: Mutual Assistance differs from GAP 58. The Mutual Assistance Invoicing procedure is used only for major storms, other natural disasters and catastrophic events that require aid for restoring electricity to the company's customers and resuming normal business operations. Mutual Assistance jobs include total cost only; no profits are gained from the aid provided. For additional information contact the associated company's storm center or comptroller.

## 2.0 General

Upon request, the Company may provide services to associated companies within Southern Company. Reference "Requesting Services" for the types of services provided. The associated companies are Southern Company Services, Alabama, Gulf and Mississippi Power Companies, Southern Telecom, Southern Company Management Development, Southern LINC Wireless, Southern Power, and Southern Nuclear. With the acquisition of Southern Company GAS, the associated companies now also include GAS and its subsidiaries. A list of GAS subsidiaries can be found on the form found [here](#).

The Company may also provide resources and employees to companies not part of The Southern Company (non-associated companies). This includes any government agencies, other utilities, industrial businesses, etc.



Company policies and guidelines documented in this procedure apply to associated operating companies and non-associated companies. When a particular process varies between the companies, GAP 58 will be the authority.

## **2.1 Budgeting for Projects**

- Project budgets should include anticipated cost of performing work
- Department providing resources should budget cost to an EWO and FERCSUB combination (and not the department's functional account)

## **3.0 Definition of Responsibilities**

### **3.1 Responsibility of Accounting Research and Regulatory Accounting**

The Accounting Research and the Regulatory Accounting departments are responsible for working with Department Managers in various areas to respond to requests and to represent the interest of the Company.

### **3.2 Responsibility of Department Manager**

The primary contact for requests is the Manager of the Business Unit providing the services. The region, plant or department manager or designee is responsible for:

- Determining employee availability
- Ensuring that an approved EWO is established for each project utilizing the GenEWO application, if available
- Ensuring all expenses charged to EWOs are appropriate and reimbursable expenses
- Ensuring that Company employees assigned to projects are notified of the appropriate EWO for allocating expenses
- Preparing billing for non-associated companies
- Notifying Financial Accounting & Reporting of completed projects
- Providing recommendations and input to Accounting Research and Regulatory Accounting regarding improvements in the reporting and billing of services provided



### 3.3 Responsibility of Financial Accounting & Reporting

Financial Accounting & Reporting is responsible for:

- Ensuring the department providing the service establishes an EWO for recording expenses for both associated and non-associated companies.
- Reviewing, verifying, billing and collecting all expenses on a monthly basis for associated companies and monitoring to ensure expenses are being cleared/paid for non-associated companies.
- Working closely with Accounting Research to monitor charges and ensure accounting accuracy.
- Coordinating the collection of past due accounts

### 3.4 Responsibility of SCS Budgeting

Southern Company GAS and its subsidiaries are not currently on the Gen EWO platform. Therefore, SCS Budgeting currently has a role in the process to:

- Receive completed "Request for Work Authorization" forms from GPC / GAS
- Determine the appropriate way to set up Y work orders so that the proper GAS Affiliate is billed for service
- Set up the Y work orders for work for GAS and provide to Georgia Power

## 4.0 Requesting Services

### 4.1 General

The Company will furnish available employees and other resources to companies requesting services, provided the loss of these resources does not have a negative impact on the quality of Company performance. All companies requesting services should contact the appropriate Department Manager for resource requirements and approval. Employees that receive requests for services should contact his/her supervisor or Department Manager prior to providing the service.



Associated Companies submit a request to the performing department using GenEWO. After approvals occur for both companies, an EWO is created along with the associated company's designated FERCSUB.

Because Southern Company GAS is not currently set up in GenEWO, Y work orders must be set up by SCS Budgeting. The cost estimating, approval, and other process documentation can be found at the link [here](#).

Non-associated Companies – request is sent the Department Manager where services are requested. The business unit providing the service is responsible for creating an EWO along with the designated FERCSUB using the GenEWO system.

#### **4.2 Available Services**

In accordance with Georgia Public Service Commission (GPSC) guidelines, Docket No. 9355-U, the Company may provide services, properties and resources to associated companies on an actual cost basis (which includes a provision for applicable overheads).

These services to associated companies, excluding SPC, include but are not limited to: website design, sale of materials associated with a service, printing, communication materials, fleet operations, calibration, substation outages, equipment repair, intercompany awards, training activities, etc.

Per the Services Agreement between SPC and GPC dated August 1, 2007, services available to SPC include labor, environmental, general construction and advisory, property accounting and other services requested by SPC.

For non-associated companies, services available and the cost of those services are in accordance with the contract price & terms.

When specifically requested, the Company may also loan employees to other companies. These employees will be under the sole supervision and control of that company until the assigned work is completed.

#### **4.3 Non-Available Services**

The determination of whether employees and resources are available is entirely within the discretion of the Department Manager. The Company may elect not to perform the requested





project. However, once an agreement has been made, the Company cannot withdraw from the project without approval from the Department Manager.

If resources are not available for the projects, resources may be added to accomplish the work under the following conditions:

- The requesting company assumes all associated start-up costs and financial risk associated with the work.
- The work does not present any undue risk for the Company's customers, employees, stockholders, or the general public.
- The costs are recovered consistent with those outlined in this procedure.
- The potential venture, risks, returns, and resources are reviewed and approved by management based on the current strategies of the Company.

#### **4.4 Estimates**

It is the responsibility of the department where the services were requested (service provider) to provide a written or verbal cost estimate to the requesting company. In the case of billing to Southern Company GAS or affiliates, the form and process found [here](#) should be utilized. Non-associated companies' estimates are based on a cost plus basis or contract price.

Under a cost plus basis:

- The requesting company pays the amount based on actual charges to the job which may be more or less than the original estimate. For Southern Company GAS, if costs exceed the original estimate by more than 120%, written approval must be obtained from GAS for the extra costs.
- Construction services for non-associated companies are billed under this method.

Under contract price billing:

- The requesting company pays the estimated amount, regardless of the actual cost.
- Non-construction services for non-associated companies are billed under this method.

#### **5.0 Recording Expenses**

The following definition/description of Research, Development and Demonstration (RD&D) projects, including FERC 188, is referenced in the FERC Manual, Title 18, CFR Ch. 1, Part 101, (4-1-07 Edition).

##### **5.1 General**



Services and other resources provided by the Company are normally accounted for and billed through an EWO. The EWO is created using the GenEWO application, or in the case of Southern Company GAS through SCS Budgeting. The department, region or plant where the service is requested is responsible for ensuring that an approved EWO is established and the appropriate amount is billed.

### **5.2 Associated Companies**

The requesting company provides a valid billing account number in GenEWO before an EWO is generated. In the case of Southern Company GAS, the form and process found [here](#) should be utilized. The EWO is then used to track the cost associated with the services provided. The business unit providing the service ensures appropriate costs are accumulated in the EWO at proper amounts. Financial Accounting and reporting is responsible for reviewing, verifying, billing and collecting all expenses on a monthly basis.

### **5.3 Non-Associated Companies**

The business unit providing the service establishes an EWO and a FERCSUB in the GenEWO application and ensures appropriate costs are charged to the EWO at proper amounts and billed to the customer on completion of the project/job.

### **5.4 Labor Expenses**

Labor hours incurred by Company employees assigned to work on projects are charged to an assigned EWO through ESTARS. Reference the ESTARS Training and Reference Manual for additional information on time reporting.

Company employees assigned to projects will continue to receive benefits (i.e. Employee Savings Plan (ESP), pension, insurance benefits, etc.). These costs are billed to the requesting company and are included in the calculation of the labor overhead rates. If the employee is out of state for a period exceeding three (3) months, he/she must contact Southern Company Payroll for the proper income tax treatment.

### **5.5 Material Expenses**

Material withdrawn from Company inventories to support projects is charged to the appropriate EWO through the Maximo System. Material purchased directly from vendors is charged to the EWO and indicated on the vendor invoice.



## 5.6 Transportation Expenses

- All operation and maintenance expenses incurred for work performed on vehicles are charged to the EWO. The EWO should also be used for fuel charges.
- Employees that use rental vehicles should charge the total rental cost to the appropriate EWO using resource type ERV.
- For estimating cost on projects, regions should contact their region comptroller/business analyst for rates regarding transportation expenses. Non-regions should contact Fleet Operations.

## 5.7 Meals, Lodging and Miscellaneous Expenses

Meals, lodging and miscellaneous expenses incurred by employees assigned to projects are charged to the appropriate EWO. Employee related business expenses may be reimbursed through the Business Expense Statement or purchased using the Purchasing Card. Reference [Business Expense Policy](#) for additional information concerning reporting employee related business expenses.

## 6.0 Billing Process

### 6.1 General

On a monthly basis Financial Accounting & Reporting is responsible for ensuring associated operating companies are billed for all costs charged to an EWO plus any overheads, if applicable, as defined in this section.

On a monthly basis the performing business unit is responsible for ensuring non-associated companies are billed for all costs charged to an EWO plus any overheads, if applicable. When the project is ready for billing, the business unit designee managing the charges creates a non-electric service billing account in the CSS application. CSS creates a bill, which is mailed to the customer.

### 6.2 Billing of Expenses

- **Labor Expenses**

Labor cost is calculated and billed based on the actual wage rate of assigned employees and the actual number of hours reported to the EWO. Overhead rates are also applied to all labor costs. The overhead rates are applied to variable and fixed direct labor cost. The overhead amount actually billed will be calculated by Power Plant. All labor costs and overhead charges are documented in Document Direct.



Reference [GAP 52, Non-Electric Service Business](#), "Rates for Estimating Jobs Performed for Customers", for the overhead rates applied to labor costs. These rates should also be used when providing cost estimates.

- **Material Expenses**

Materials withdrawn from the Company inventory, for associated companies and non-associated companies, are billed at average unit price. Materials purchased directly from vendors for use on projects is billed at invoice cost. Reference [GAP 61 - Accounting for Company Materials](#) for additional information.

- **Transportation Expenses**

Vehicle and equipment expenses will be billed based on the labor hours charged to the projects. Therefore, accurate labor hours for each project must be charged to the appropriate EWO. Reference [GAP 60, Fleet Usage & Expense Reporting](#) for additional information. Rental vehicle expenses are billed at actual cost. Rental vehicle expenses are billed at actual cost. Mileage is billed based on the actual miles.

- **Meals, Lodging and Miscellaneous Expenses**

Meals, lodging and miscellaneous expenses are billed at actual cost.

### 6.3 Invoice

- **Associated Companies**

Financial Accounting & Reporting is responsible for ensuring the proper billing of monthly charges for all services provided to requesting companies. All associated operating companies and SPC are billed electronically utilizing GenEWO. All costs (labor, overhead, materials, etc.) are documented in a monthly report generated in Mobius (Document Direct).

There may be expenses where charges are billed manually. Financial Accounting & Reporting is responsible for preparing the invoices for all services provided to requesting companies.

For Southern Telecom, Southern Company Management Development and Southern Linc Wireless a separate invoice is issued. The invoice summarizes charges by EWO.

- **Non-Associated Companies**

An invoice generated in the CSS application is provided to non-associated companies for billing purposes.



## **7.0 Joint Ownership**

### **7.1 General**

The Company jointly owns certain generating plants with six (6) utility companies. The joint owners are Municipal Electric Authority of Georgia (MEAG), Oglethorpe Power (OPC), City of Dalton (Dalton), Gulf Power Company, Florida Power & Light, and Jacksonville Electric Authority.

In addition, the Company participates in an Integrated Transmission System (ITS) arrangement with the other owners of transmission assets in the state of Georgia. These owners are the Georgia Transmission Corporation (GTC), MEAG, and Dalton.

Joint ownership requests are facilitated through Joint Ownership Accounting (JOA). JOA is responsible for ensuring that all joint ownership contracts are executed and expenses are properly reported.

### **7.2 Generating Plants**

The Company is the operator of the jointly owned plants excluding the Rocky Mountain Pumped Storage Hydro (PSH) facility. (This is no longer applicable). As operator, the Company incurs capital improvement, operation and maintenance (O&M) and administrative and general (A&G) costs and can bill the joint owners in accordance with the contracts for these costs.

O&M expenses include direct on-site costs as well as certain allocated costs. Capital improvement billings include normal capital overheads, except AFUDC. All capital improvements and most O&M costs are billed to the co-owners on a pro rata ownership basis. Employee benefit costs and other (A&G) expenses that support the operation of these plants are also billed to the co-owners.

### **7.3 Integrated Transmission System**

The Company sold certain transmission assets to GTC (formally OPC), MEAG, and Dalton. This created the ITS. The ITS allows each company to own individual lines, substations, and other facilities rather than individual interests in the entire system. The participants have the right to use the ITS system to serve their customers.

JOA bills all ITS participants for system operator expenses on a pro rata ownership basis or contract price basis. Maintenance expenses for Dalton are also billed on a pro rata ownership basis. ITS maintenance performed for GTC and MEAG is charged and billed per an EWO.



Reference [GAP 55, General Work Orders](#) for additional information on the processing and preparation of an EWO for GTC, MEAG and Dalton.

## **8.0 Special Processing**

### **8.1 Federal Governmental Billing**

Contracting with the federal government to share resources for research programs or to provide services, obligates the Company to perform in accordance with specific federal government contracting rules and regulations relative to cost, time keeping, administration, materials handling, etc. Therefore, prior to providing services or resources to the federal government, contact SCS Legal/General Counsel for assistance with the proper format and guidelines for approving government contracts. They will also assist with contract close-out activities, contract termination, resolution of claims and interface with government representatives.

## **9.0 Additional Account Segments**

Additional Account Segments are used in conjunction with the EWO to accumulate all costs associated with the services provided to requesting companies. Listed below is the information required for each affiliate billing account.

**Required Account Segments** - these fields must be completed to ensure proper accounting & billing.

**PRCN** This five character field identifies the appropriate Performing Responsibility Center Number (PRCN). This segment identifies which subsidiary organizational unit did the work, incurred the cost and, in some cases, generated the revenue.

**RT** The four character cost type field classifies the type of expense. Identifies the type of cost incurred, revenue generated, resource used to perform the work (labor/material), etc., including charge-backs (print shop, IT, etc.). Access the on-line Account Validation Inquiry (AVI) system for a list of cost types. The AVI system is restricted to authorized users only. Resource Type (RT).



EWO This six character field is used to track: 1) costs for work performed; or 2) profitability of products/services/contracts. Expenditure Work Order (EWO).

FERC/SUB The eight (FERC=3, SUB=5) character field records and reports transactions according to regulatory and compliance requirements.

Company Code Three characters.

**Optional Account Segments** – if not entered, a default value of all zeroes will be entered by the system

Activity Code A seven character field intended to describe the general nature of work being performed.  
Activities represent common, ongoing tasks as defined by functional business units, subsidiaries, or Southern Company (for system-wide activities).

Project This six character segment describes the work to be performed at a summary/rollup level.

Location The five character field identifies the physical or geographic location; physical asset; cost pool/accounting location; synthetic lease; & mass property general asset categories.

RORG The five character field records which business unit is authorizing the work and receiving either benefit from the work or revenues. Receiving Organization (ROrg).

BWO The six character field to be used by the affiliate companies to budget and report the receipt of affiliate billings at the detail work/job order/sub account level. Billing Work Order (BWO) effective October 1, 2009.



Allocation  
Indicator

Two characters. Not required input. Allocation indicators are applied by the system after allocations.