Georgia Power

Bin 10230
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374

May 1, 2023

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

RE: 2022 Annual Report of Major Electric Utilities, Licensees and Others Federal Energy Regulatory Commission (FERC) Form No. 1

Dear Ms. Tanner:

Attached please find a copy of Georgia Power's FERC Form No. 1 Annual Report for the year ending December 31, 2022.

Please call me at 404-506-3044 with any questions regarding this filing.

Sincerely,

/s/ Kelley M. Balkcom

Kelley M. Balkcom
Director, Regulatory Affairs
mmcclosk@southernco.com

SUPPLEMENTAL OATH

(By the President or other Chief Officer of the Respondent).

State of: Georgia

County of: Fulton

Kimberly S. Greene makes oath and says that she is
(Name of the Affiant)

Chairman, President and Chief Executive Officer of
(Official Title of the Affiant)

Georgia Power Company
(Exact Legal Title or Name of the Respondent)

that she has examined the foregoing report; that she believes that all statements of fact contained in the said report are true, and the said report is a correct statement of the business and affairs of the above named Respondent in respect to each and every matter set forth therein during the period from and including January 1, 2022 to and including December 31, 2022

Kimberly S Greene
(Signature of Affiant)

Subscribed and sworn to before me, a Notary Public in and for the State and County above named, this 20th day of April 2023

My Commission expires:

July 10, 2026 (Use an Impression Seal.)

Elizabeth Claire Green
(Signature of Officer authorized to administer oaths)

ELIZABETH CLAIRE GREEN
My Commission Expires
NOTARY
PUBLIC
July 10, 2026
DEKALB COUNTY, GEORGIA

VERIFICATION

The foregoing report must be verified by the oath of the Officer having control of the accounting of the Respondent. It should be verified, also, by the oath of the president or Chief Officer of the Respondent. The oath required may be taken before any person authorized to administer an oath by the laws of the State in which the same is taken.

OATH

(To be made by the Officer having control of the accounting of the Respondent.)

State of: Georgia

County of: Fulton

Aaron P. Abramovitz makes oath and says that he is
(Name of the Affiant)

Executive Vice President, Chief Financial Officer, and Treasurer of
(Official Title of the Affiant)

Georgia Power Company that it is his duty to have
(Exact Legal Title or Name of the Respondent)

supervision over the books of account of the Respondent and that to the best of his knowledge and belief such books have, during the period covered by the foregoing report, been kept in good faith in accordance with the accounting and other orders of the Georgia Public Service Commission, effective during said period; that he has examined the said report, and to the best of his knowledge and belief the information contained in the said report is, insofar as it relates to matters of account, in accordance with the said books of account; that he believes that all other statements of fact contained in said report are true, and that the said report is a correct statement of the business and affairs of the above named Respondent in respect to each and every matter set forth therein during the period from and including January 1, 2022 to and including December 31, 2022

(Signature of Affiant)

Subscribed and sworn to before me, A Notary Public in and for the State and County above named, this 20th day of April 2023

My commission expires:

July 10, 2026

(Use an Impression Seal.)

(Signature of Officer authorized to administer oaths)

ELIZABETH CLAIRE GREEN
NOTARY PUBLIC
DEKALB COUNTY, GEORGIA
My Commission Expires
July 10, 2026

THIS FILING IS
Item 1: ☐ An Initial (Original) Submission OR ☑ Resubmission No.

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Georgia Power Company	End of: 2022/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions,

reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods

entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

4. 'Person' means an individual or a corporation;

5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309

adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

FERC FORM NO. 1 (ED. 03-07)

Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Georgia Power Company	End of: 2022/ Q4

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
241 Ralph McGill Blvd, NE, Atlanta, GA 30308-3374

05 Name of Contact Person	06 Title of Contact Person
Matthew Humphrey	Financial Accounting and Reporting Manager

07 Address of Contact Person (Street, City, State, Zip Code)
241 Ralph McGill Blvd, NE, Atlanta, GA 30308-3374

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
404-506-7136	(1) ☐ An Original (2) ☑ A Resubmission	04/20/2023

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Sarah P. Adams	Sarah P. Adams	04/20/2023
02 Title Vice President and Comptroller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	**General Information**	101	
2	**Control Over Respondent**	102	
3	**Corporations Controlled by Respondent**	103	
4	**Officers**	104	
5	**Directors**	105	
6	**Information on Formula Rates**	106	
7	**Important Changes During the Year**	108	
8	**Comparative Balance Sheet**	110	
9	**Statement of Income for the Year**	114	
10	**Statement of Retained Earnings for the Year**	118	
12	**Statement of Cash Flows**	120	
12	**Notes to Financial Statements**	122	
13	**Statement of Accum Other Comp Income, Comp Income, and Hedging Activities**	122a	
14	**Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep**	200	
15	**Nuclear Fuel Materials**	202	
16	**Electric Plant in Service**	204	
17	**Electric Plant Leased to Others**	213	
18	**Electric Plant Held for Future Use**	214	
19	**Construction Work in Progress-Electric**	216	
20	**Accumulated Provision for Depreciation of Electric Utility Plant**	219	
21	**Investment of Subsidiary Companies**	224	
22	**Materials and Supplies**	227	
23	**Allowances**	228	
24	**Extraordinary Property Losses**	230a	
25	**Unrecovered Plant and Regulatory Study Costs**	230b	
26		231	

	Transmission Service and Generation Interconnection Study Costs		
27	**Other Regulatory Assets**	232	
28	**Miscellaneous Deferred Debits**	233	
29	**Accumulated Deferred Income Taxes**	234	Revised
30	**Capital Stock**	250	
31	**Other Paid-in Capital**	253	
32	**Capital Stock Expense**	254b	None
33	**Long-Term Debt**	256	
34	**Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax**	261	
35	**Taxes Accrued, Prepaid and Charged During the Year**	262	Revised
36	**Accumulated Deferred Investment Tax Credits**	266	
37	**Other Deferred Credits**	269	
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	Revised
43	**Regional Transmission Service Revenues (Account 457.1)**	302	None
44	**Sales of Electricity by Rate Schedules**	304	Revised
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	None
50	**Transmission of Electricity by Others**	332	
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	None
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	

60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	Revised
62	**Monthly Peaks and Output**	401b	Revised
63	**Steam Electric Generating Plant Statistics**	402	Revised
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	
66	**Generating Plant Statistics Pages**	410	
0	**Energy Storage Operations (Large Plants)**	414	None
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Sarah P. Adams

Vice President and Comptroller

241 Ralph McGill Blvd, NE, Atlanta, GA 30308-3374

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: GA

Date of Incorporation: 1930-06-26

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric light and power - Georgia

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

(a) Name of controlling corporation: The Southern Company (Southern Company), a Delaware corporation.

(b) Extent of control: All common stock of respondent is owned by Southern Company.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Southern Electric Generating Company	Public Utility	50%	(a)
2	Piedmont-Forrest Corporation	Subsidiary established for the purpose of handling various real estate related transactions.	100%	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: FootnoteReferences

(a) 50.00% of Southern Electric Generating Company's capital stock is owned by Georgia Power Company and 50.00% is owned by Alabama Power Company.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Chairman, President and Chief Executive Officer	Christopher C. Womack	895,212		
2	Executive Vice President, Chief Financial Officer, and Treasurer	Aaron P. Abramovitz	399,660		
3	Executive Vice President External Affairs and Nuclear Development	Meredith M. Lackey	475,783		
4	Senior Vice President General Counsel, Corporate Secretary, and CCO	Sterling A. Spainhour	468,978		
5	Charitable Giving Senior Vice President	Michael K. Anderson	347,766		
6	Senior Vice President, Human Resources	Sloane Drake	444,146		
7	Senior Vice President and Senior Production Officer - East Production Group	Allen Reaves	350,122		
8	Senior Vice President, Power Delivery	Fran Forehand	339,431		
9	Senior Vice President, Customer and Corporate Services	Nicole Faulk	87,585		2022-04-01
10	Senior Vice President, Customer Strategy and Solutions	Bentina Terry	364,623	2022-04-01	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Christopher C. Womack, Chairman, President and CEO	241 Ralph McGill Blvd NE, BIN 10240 Atlanta, GA 30308	true	true
2	Mark L. Burns	500 Gulfstream Road, Savannah, GA 31408	false	false
3	Jill Campbell	N/A	false	false
4	Shantella E. Cooper	Five Concourse Parkway, Suite 3000, Atlanta, GA, 30328	true	false
5	Lawrence L. Gellerstedt, III	3350 Riverwood Parkway Suite 400, Atlanta, GA 30339	false	false
6	[a] Douglas J. Hertz (A)	5500 United Drive, Smyrna, GA 30082	false	false
7	Thomas M. Holder	3300 Riverwood Pkwy, Ste. 1200, Atlanta, GA 30339	false	false
8	Kessel D. Stelling, Jr.	N/A	true	false
9	Charles K. Tarbutton	750 Sparta Road, Sandersville, GA 31082	true	false
10	Clyde C. Tuggle	4473 Northside Parkway, Atlanta, GA. 30327	true	false
11	Andrew W. Evans	N/A	false	false

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector

Retired effective May, 2022

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Georgia Power Company Rate Schedule Federal Energy Regulatory Commission (FERC) No. 793	Initial docket not available on eLibrary
2	Georgia Power Company Rate ScheduleFERC No. 833	ER99-3051-000
3	Georgia Power Company Rate ScheduleFERC No. 835	ER02-1574-000
4	Georgia Power Company Rate Schedule No. 850, Oglethorpe & Georgia System Operations Corporation Control Area Compact	ER16-2672-000
5	Tariff Volume No. 5, Southern CompaniesOpen Access Transmission Tariff	ER18-1934-001
6	Cost Based Rate Tariff,Southern's Tariff Volume No. 11	ER10-2925-000
7	Southern Company Services, Inc.FERC Electric Tariff Original Volume No. 13	ER21-233-000
8	Southern Operating CompaniesFirst Revised Rate Schedule FERC No. 33	ER19-1000-000
9	Southern Company Services, Inc.Second Revised Rate Schedule FERC No. 138	ER22-1820-001

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20211101-5317	11/01/2021	ER10-203-000	2022 OATT Informational Filing	Tariff Volume No. 5, Southern Companies OATT
2	20220429-5688	04/29/2022	ER10-203-000	2021 OATT True-Up Filing	Tariff Volume No. 5, Southern Companies OATT
3	20211101-5320	11/01/2021	ER10-171-000	2022 Intercompany Interchange Contract Informational Filing	Southern Company Services, Inc. Second Revised Rate Schedule
4	20211102-5166	11/02/2021	ER10-171-000	Supplement to 2022 Intercompany Interchange Contract	Southern Company Services, Inc. Second Revised Rate Schedule
5	20220518-5149	05/18/2022	ER10-171-000	Updated 2022 Intercompany Interchange Contract Informational Filing	Southern Company Services, Inc. Second Revised Rate Schedule FERC No. 138

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	None			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None

2. None

3. During the second quarter ending June 30, 2022, under Docket No. EC21-105-000, Georgia Power requested and the Commission approved proposed accounting entries to clear Account 102, Electric Plant Purchased or Sold for the sale of transmission lines known as the Jonesville Tap 115kV, the South Bainbridge -Thomasville 115kV, and 31 additional 46kV transmission lines for approximately $54 million.

4. None

5. None

6. The following obligations were incurred as a result of the issuance of securities pursuant to Federal Energy Regulatory Commission approval:

Georgia Power Company issued commercial paper from time to time during the year ended December 31, 2022. The largest amount of such commercial paper outstanding at any given time during such period was $635 million.

In February 2022, Georgia Power borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement.

In each of March and April 2022, Georgia Power entered into a $200 million short-term floating rate bank loan bearing interest based on term SOFR.

In October 2022, Georgia Power borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement.

In November 2022, Georgia Power entered into a $1.2 billion short-term floating rate bank loan bearing interest based on term SOFR.

The following obligations were incurred as a result of the issuance of securities pursuant to Georgia Public Service Commission approval:

In May 2022, Georgia Power issued $700 million aggregate principal amount of Series 2022A 4.70% Senior Notes due May 15, 2032 and $800 million aggregate principal amount of Series 2022B 5.125% Senior Notes due May 15, 2052.

In November 2022, the Development Authority of Bartow County (Georgia) issued for the benefit of Georgia Power approximately $200 million aggregate principal amount of Solid Waste Disposal Facility Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2022 ($100 million aggregate principal amount) and Second Series 2022 ($100 million aggregate principal amount) due November 1, 2062.

7. None

8. None

9. See Note 3 to the Financial Statements for a description of certain legal proceedings.

10. None

12. See pages 122 through 123.

13. Effective January 1, 2022, Andrew W. Evans was elected Director.

Effective January 22, 2022, John L. Cornelius, Jr. was elected Vice President.

Effective February 21, 2022, Charles E. Sutlive, Jr. was elected Vice President.

Effective March 25, 2022, Valerie R. Hendrickson resigned as Vice President.

Effective April 1, 2022, Theodore J. McCullough resigned as Vice President.

Effective April 1, 2022, Jeff G. Franklin resigned as Vice President.

Effective April 1, 2022, A. Nicole Faulk resigned as Senior Vice President.

Effective April 1, 2022, Lisa J. Smith was elected as Senior Vice President.

Effective April 1, 2022, Walt Farrell was elected as Vice President.

Effective April 1, 2022, Erin P. Harris was elected as Vice President.

Effective April 15, 2022, Wendell Dallas resigned as Vice President.

Effective May 13, 2022, Tequila G. Smith resigned as Vice President.

Effective May 18, 2022, Molly Aeck was elected as Vice President.

Effective May 18, 2022, Douglas J. Hertz resigned as Director.

Effective June 20, 2022, Mark. S. Berry resigned as Vice President.

Effective June 20, 2022, Aaron D. Mitchell was elected as Vice President.

Effective June 20, 2022, Jennifer H. Winn was elected as Vice President.

Effective August 27, 2022, Cleveland L. Fann was elected as Vice President.

Effective January 16, 2023, Chimaobi Chijioke was elected as Vice President.

Effective February 16, 2023, Larry L. Gellerstedt, III resigned as a Director.

Effective March 31, 2023, Christopher C. Womack resigned as Chairman, President and Chief Executive Officer.

Effective March 31, 2023, Kimberly S. Greene was elected as Chairman, President and Chief Executive Officer.

Effective March 31, 2023, Sloane N. Drake resigned as Senior Vice President.

Effective March 31, 2023, R. Allen Reaves, Jr. resigned as Senior Vice President.

Effective April 1, 2023, Sterling A. Spainhour resigned as Senior Vice President, Corporate Secretary and Chief Compliance Officer.

Effective April 1, 2023, Erin P. Harris resigned as Vice President.

Effective April 1, 2023, David E. Slovensky was elected as Senior Vice President, Corporate Secretary and Chief Compliance Officer.

Effective April 1, 2023, Lindsay R. Hill was elected as Senior Vice President.

Effective April 1, 2023, Roderick W. Anderson was elected as Senior Vice President.

Effective April 1, 2023, John B. Williams was elected as Senior Vice President.

Effective April 1, 2023, Jennifer S. McNelly was elected as Vice President.

Effective April 1, 2023, Erica McGill was elected as Vice President.

14. N/A

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	43,455,117,881	42,912,778,602
3	Construction Work in Progress (107)	200	8,120,609,322	6,763,769,568
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		51,575,727,203	49,676,548,170
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	13,156,790,331	12,983,897,038
6	Net Utility Plant (Enter Total of line 4 less 5)		38,418,936,872	36,692,651,132
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	237,956,861	209,042,302
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		225,452,810	202,443,033
9	Nuclear Fuel Assemblies in Reactor (120.3)		480,388,723	493,957,304
10	Spent Nuclear Fuel (120.4)			49,294,028
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	340,156,168	377,637,311
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		603,642,226	577,099,356
14	Net Utility Plant (Enter Total of lines 6 and 13)		39,022,579,098	37,269,750,488
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		116,883,892	79,697,478
19	(Less) Accum. Prov. for Depr. and Amort. (122)		13,654,690	11,556,979
20	Investments in Associated Companies (123)		11,172,731	9,348,805
21	Investment in Subsidiary Companies (123.1)	224	57,341,286	58,200,976
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		4,879,512	1,579,233
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		[a]2,696,338,317	2,712,722,532
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			

31	Long-Term Portion of Derivative Assets - Hedges (176)		6,344,516	21,075,340
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,879,305,564	2,871,067,385
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		9,462,364	32,723,188
36	Special Deposits (132-134)		60,000,000	
37	Working Fund (135)			
38	Temporary Cash Investments (136)		355,000,000	
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		737,129,340	548,677,982
41	Other Accounts Receivable (143)		175,852,740	149,315,022
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,535,162	1,630,958
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		53,100,053	25,485,430
45	Fuel Stock (151)	227	281,851,393	241,180,197
46	Fuel Stock Expenses Undistributed (152)	227	2,315,874	
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	728,169,157	670,036,725
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227	389,375	412,467
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	7,239,520	7,254,800
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	(45,306)	
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		95,836,363	45,979,081
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		1,285,084	22,433
60	Rents Receivable (172)		16,137,113	14,432,358
61	Accrued Utility Revenues (173)		342,459,403	264,034,405
62	Miscellaneous Current and Accrued Assets (174)		58,822,027	31,040,152
63	Derivative Instrument Assets (175)		26,000	
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)		41,717,326	75,049,571

66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		6,344,516	21,075,340
67	Total Current and Accrued Assets (Lines 34 through 66)		2,957,868,148	2,082,937,513
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		117,257,256	113,334,308
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	7,610,374,834	7,280,877,071
73	Prelim. Survey and Investigation Charges (Electric) (183)		25,728,060	29,666,773
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		872,501	79,547
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	2,378,737,375	747,686,149
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		213,071,369	230,884,472
82	Accumulated Deferred Income Taxes (190)	234	1,495,476,493	[b]1,597,317,957
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		11,841,517,888	9,999,846,277
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		56,701,270,698	52,223,601,663

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherSpecialFunds

Other Special Funds (128)		
Restricted Cash	$	55,712,734
External Trusts		2,640,625,583
Other Special Funds (128)	**$**	**2,696,338,317**

(b) Concept: AccumulatedDeferredIncomeTaxes

ACCUMULATED DEFERRED INCOME TAXES (ACCOUNT 190)	BALANCE AT BEG OF YEAR	BALANCE AT END OF YEAR
Accrual for Uncollectibles	$ 415,433	$ 645,749
Accumulated Rate Refund Georgia Public Service Commission	1,806,427	30,824,146
Affirmative Adjustments*	-	8,478,950
Capacity Buybacks*	56,038	7,630
Capitalized Purchase Power Agreement Southern Power Co	9,576,608	8,472,722
Deferred Revenues - Electric	183,066	54,237
Demand Side Management Recovery	14,947,457	9,580,081
FAS 133 Mark to Market*	7,269,519	7,763,311
GA Rate Change Reserve Gross Up	867,287	-
Health Reimbursement Accrual	513,722	587,397
Income Taxes Deferred - Electric	212,973,444	243,576,200
Protected Gross Up EADIT	568,818,102	552,719,580
Income Taxes Deferred - CWIP Electric	(15,810,215)	(18,292,275)
Income Taxes Deferred - Non Electric*	2,342,190	3,070,827
Income Taxes Deferred - CWIP Non Electric*	(36,772,655)	(39,575,884)
Injuries & Damages Reserve	1,397,696	3,862,585
Nuclear Construction Cost Recovery Over/Under Recovery	3,962,448	-
Other Comprehensive Income - Hedge Settlement	13,785,008	4,064,883
Other Basis Differences	84,270,634	74,181,501
Accrued Liabilities - Electric	112,814,670	110,588,151
Accrued Liabilities - Non Electric*	28,789,974	15,461,181
Storm Damage	-	22,214,683
Tax Credit Carry Forward - Electric	345,119,713	346,558,564
Tax Credit Carry Forward - Non Electric*	198,138,582	124,293,426
Unbilled Fuel Revenues	23,822,210	23,051,473
Unprotected Gross Up EADIT	54,743,224	-
Unprotected Gross Up Deficient EADIT NCCR	(36,712,625)	(36,712,625)
Total	$ 1,597,317,957	$ 1,495,476,493
*Other Income and Deductions		
Classification of Totals:		
Federal Income Tax	$ 924,508,257	$ 882,849,107
State Income Tax	$ 672,809,700	$ 612,627,386

** Resubmission - update to include this footnote

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	398,473,175	398,473,175
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		8,664,636	8,664,636
7	Other Paid-In Capital (208-211)	253	15,616,448,441	14,143,642,821
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	2,805,711,814	2,682,952,071
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	40,729,734	40,815,711
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(12,479,411)	(40,919,777)
16	Total Proprietary Capital (lines 2 through 15)		18,857,548,389	17,233,628,637
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	100,000,000	129,000,000
19	(Less) Reaquired Bonds (222)	256	329,485,000	358,485,000
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	15,036,793,026	14,002,661,576
22	Unamortized Premium on Long-Term Debt (225)		2,719,713	2,861,293
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		20,571,398	13,998,106
24	Total Long-Term Debt (lines 18 through 23)		14,789,456,341	13,762,039,763
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		1,073,056,879	1,125,119,351
27	Accumulated Provision for Property Insurance (228.1)		83,324,714	
28	Accumulated Provision for Injuries and Damages (228.2)		38,648,814	26,514,833
29	Accumulated Provision for Pensions and Benefits (228.3)		1,162,644,720	1,290,957,764

30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		121,226,243	7,810,605
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		18,452,199	1,613,269
34	Asset Retirement Obligations (230)		6,034,809,600	6,824,215,342
35	Total Other Noncurrent Liabilities (lines 26 through 34)		8,532,163,169	9,276,231,164
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		1,600,000,000	
38	Accounts Payable (232)		1,052,446,993	683,166,758
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		928,282,719	756,624,397
41	Customer Deposits (235)		251,630,642	259,128,948
42	Taxes Accrued (236)	262	508,090,352	335,281,114
43	Interest Accrued (237)		156,625,169	136,194,879
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		23,654,376	18,958,507
48	Miscellaneous Current and Accrued Liabilities (242)		492,629,735	477,882,015
49	Obligations Under Capital Leases-Current (243)		166,831,743	165,820,590
50	Derivative Instrument Liabilities (244)		579,142	637,783
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)		61,651,880	7,614,255
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		18,452,199	1,613,269
54	Total Current and Accrued Liabilities (lines 37 through 53)		5,223,970,552	2,839,695,977
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		99,470,668	43,564,906
57	Accumulated Deferred Investment Tax Credits (255)	266	318,833,007	327,531,349
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	268,464,320	279,489,170
60	Other Regulatory Liabilities (254)	278	3,409,276,739	3,845,443,130
61	Unamortized Gain on Reaquired Debt (257)		27,358	51,070
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	564,996,931	620,990,012

63	Accum. Deferred Income Taxes-Other Property (282)		3,174,006,201	3,176,765,624
64	Accum. Deferred Income Taxes-Other (283)		1,463,057,023	818,170,861
65	Total Deferred Credits (lines 56 through 64)		9,298,132,247	9,112,006,122
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		56,701,270,698	52,223,601,663

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) t amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proc revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense ac
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, incl allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to th

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previou Year to Date (in dollars (j)
1	UTILITY OPERATING INCOME									
2	Operating Revenues (400)	300	11,439,781,440	9,107,472,270			11,439,781,440	9,107,472,270		
3	Operating Expenses									
4	Operation Expenses (401)	320	6,099,396,772	4,245,852,642			6,099,396,772	4,245,852,642		
5	Maintenance Expenses (402)	320	702,935,280	640,164,823			702,935,280	640,164,823		
6	Depreciation Expense (403)	336	1,106,480,748	1,081,182,046			1,106,480,748	1,081,182,046		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	38,776,261	39,548,089			38,776,261	39,548,089		
8		336	50,002,191	38,994,647			50,002,191	38,994,647		

	Amort. & Depl. of Utility Plant (404-405)									
9	Amort. of Utility Plant Acq. Adj. (406)	336	640,752	640,752			640,752	640,752		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)									
11	Amort. of Conversion Expenses (407.2)									
12	Regulatory Debits (407.3)		327,779,378	296,250,192			327,779,378	296,250,192		
13	(Less) Regulatory Credits (407.4)		314,411,175	322,934,637			314,411,175	322,934,637		
14	Taxes Other Than Income Taxes (408.1)	262	526,370,084	475,976,440			526,370,084	475,976,440		
15	Income Taxes - Federal (409.1)	262	50,695,948	332,363,439			50,695,948	332,363,439		
16	Income Taxes - Other (409.1)	262	42,249,407	23,262,451			42,249,407	23,262,451		
17	Provision for Deferred Income Taxes (410.1)	234, 272	908,876,961	481,249,478			908,876,961	481,249,478		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	631,659,071	593,841,186			631,659,071	593,841,186		
19	Investment Tax Credit Adj. - Net (411.4)	266	(8,938,554)	(7,584,804)			(8,938,554)	(7,584,804)		
20	(Less) Gains from Disp. of Utility Plant (411.6)		742,644	549,084			742,644	549,084		
21	Losses from Disp. of Utility Plant (411.7)		6,984				6,984			
22	(Less) Gains from Disposition of Allowances (411.8)		221	105			221	105		
23	Losses from Disposition of Allowances (411.9)									
24	Accretion Expense (411.10)		231,052,096	235,987,370			231,052,096	235,987,370		

25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		9,129,511,197	6,966,562,553			9,129,511,197	6,966,562,553		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		2,310,270,243	2,140,909,717			2,310,270,243	2,140,909,717		
28	Other Income and Deductions									
29	Other Income									
30	Nonutilty Operating Income									
31	Revenues From Merchandising, Jobbing and Contract Work (415)		142,879,488	151,382,826						
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		116,825,741	117,093,732						
33	Revenues From Nonutility Operations (417)		19,543	(76,049)						
34	(Less) Expenses of Nonutility Operations (417.1)		2,343,608	1,637,299						
35	Nonoperating Rental Income (418)		17,200,000	15,445,364						
36	Equity in Earnings of Subsidiary Companies (418.1)	119	6,260,005	5,887,392						
37	Interest and Dividend Income (419)		10,156,495	2,570,243						
38	Allowance for Other Funds Used During Construction (419.1)		156,412,191	127,713,523						
39	Miscellaneous Nonoperating Income (421)		20,132,833	17,138,596						
40	Gain on Disposition of Property (421.1)		17,641,954	3,182,536						
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		251,533,160	204,513,400						

42	Other Income Deductions									
43	Loss on Disposition of Property (421.2)		109,916	334,490						
44	Miscellaneous Amortization (425)		50,021	50,021						
45	Donations (426.1)		50,576,543	26,768,237						
46	Life Insurance (426.2)		(237,374)	(238,094)						
47	Penalties (426.3)		11,187	161,350						
48	Exp. for Certain Civic, Political & Related Activities (426.4)		19,181,175	10,328,514						
49	Other Deductions (426.5)		199,850,003	1,709,054,193						
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		269,541,471	1,746,458,711						
51	Taxes Applic. to Other Income and Deductions									
52	Taxes Other Than Income Taxes (408.2)	262	15,129,366	14,438,453						
53	Income Taxes-Federal (409.2)	262	(12,665,915)	(21,239,201)						
54	Income Taxes-Other (409.2)	262	(62,876,965)	47,926,569						
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	241,478,463	97,164,908						
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	165,943,651	534,167,863						
57	Investment Tax Credit Adj.-Net (411.5)									
58	(Less) Investment Tax Credits (420)									
59			15,121,298	(395,877,134)						

	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)									
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(33,129,609)	(1,146,068,177)						
61	Interest Charges									
62	Interest on Long-Term Debt (427)		480,819,503	429,396,708						
63	Amort. of Debt Disc. and Expense (428)		10,671,535	18,089,946						
64	Amortization of Loss on Reaquired Debt (428.1)		21,418,808	10,148,862						
65	(Less) Amort. of Premium on Debt-Credit (429)		165,291	154,087						
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			11,528						
67	Interest on Debt to Assoc. Companies (430)		2,312,819	194,833						
68	Other Interest Expense (431)		34,594,807	16,396,834						
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		85,865,313	63,092,343						
70	Net Interest Charges (Total of lines 62 thru 69)		463,786,868	410,969,225						
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,813,353,766	583,872,315						
72	Extraordinary Items									
73	Extraordinary Income (434)									
74	(Less) Extraordinary Deductions (435)									

75	Net Extraordinary Items (Total of line 73 less line 74)									
76	Income Taxes-Federal and Other (409.3)	262	0							
77	Extraordinary Items After Taxes (line 75 less line 76)									
78	Net Income (Total of line 71 and 77)		1,813,353,766	583,872,315						

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,620,046,265	3,688,493,966
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		1,807,093,761	577,984,923
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	(a) Hydro Amortization Reserve, Federal		(7,906,804)	(4,071,493)
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(7,906,804)	(4,071,493)
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	(b) FOOTNOTE		(1,690,680,000)	(1,649,240,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(1,690,680,000)	(1,649,240,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		6,345,982	6,878,869
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,734,899,204	2,620,046,265
39	APPROPRIATED RETAINED EARNINGS (Account 215)			

45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		70,812,610	62,905,806
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		70,812,610	62,905,806
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,805,711,814	2,682,952,071
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		40,815,711	41,807,188
50	Equity in Earnings for Year (Credit) (Account 418.1)		6,260,005	5,887,392
51	(Less) Dividends Received (Debit)		6,345,982	6,878,869
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		40,729,734	40,815,711

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AppropriationsOfRetainedEarningsDescription

The hydro amortization reserve calculation is an annual calculation that is required by the FERC under Order 550, which became effective on May 1, 1976. The order requires that earnings must be calculated on all licensed hydro projects using the Company's rate of return and then compared with earnings that are calculated using the FERC's specified rate of return. One half of any excess earnings must be appropriated in retained earnings.

(b) Concept: DividendsDeclaredCommonStockDescription

Note 1: Dividend Declarations

	2022	2021
Common Stock	$ 1,690,680,000	$ 1,649,240,000

All common stock of the respondent is owned by Southern Company.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	1,813,353,766	583,872,315
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,174,053,127	1,148,245,343
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of		
5.2	Nuclear Fuel	122,644,692	127,867,756
5.3	Other	321,827,717	313,366,504
8	Deferred Income Taxes (Net)	313,807,901	(549,632,165)
9	Investment Tax Credit Adjustment (Net)	30,006,247	(7,547,304)
10	Net (Increase) Decrease in Receivables	(286,814,563)	80,610,371
11	Net (Increase) Decrease in Inventory	(116,258,117)	(52,001,816)
12	Net (Increase) Decrease in Allowances Inventory	15,280	18,038
13	Net Increase (Decrease) in Payables and Accrued Expenses	611,527,253	99,932,782
14	Net (Increase) Decrease in Other Regulatory Assets	63,070,138	217,891,494
15	Net Increase (Decrease) in Other Regulatory Liabilities	69,034,429	(15,913,530)
16	(Less) Allowance for Other Funds Used During Construction	156,412,191	127,713,523
17	(Less) Undistributed Earnings from Subsidiary Companies	6,260,006	5,825,381
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):		
18.2	Estimated Loss on Plant Vogtle Units 3 and 4	183,348,000	1,692,149,824
18.3	Other, Net	[a](2,094,169,429)	[f](724,433,400)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	2,042,774,244	2,780,887,308
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		

26	Gross Additions to Utility Plant (less nuclear fuel)	(3,921,626,054)	(3,387,794,767)
27	Gross Additions to Nuclear Fuel	(141,172,992)	(150,140,538)
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(156,412,191)	(127,713,523)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(3,906,386,855)	(3,410,221,782)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies	(4,135,061)	(446,819)
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables	(13,810,568)	21,926,323
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	200,179,495	(86,522,595)
53	Other (provide details in footnote):		
53.1	Fixed Assets	55,994,379	8,057,954
53.2	Other (provide details in footnote):	[b](290,611,212)	[g](156,807,961)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(3,958,769,822)	(3,624,014,880)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,700,000,000	1,311,167,896
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Short-Term Borrowings	2,100,000,000	
66	Net Increase in Short-Term Debt (c)		

67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contributions from Parent Company	1,470,616,486	1,782,408,285
70	Cash Provided by Outside Sources (Total 61 thru 69)	5,270,616,486	3,093,576,181
72	Payments for Retirement of:		
73	Long-term Debt (b)	(665,868,550)	(498,205,133)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	(c)(50,620,448)	(b)(19,606,329)
76.2	Short-Term Borrowings	(500,000,000)	
78	Net Decrease in Short-Term Debt (c)		(60,000,000)
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(1,690,680,000)	(1,649,240,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	2,363,447,488	866,524,719
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	447,451,910	23,397,147
88	Cash and Cash Equivalents at Beginning of Period	(d)32,723,188	9,326,041
90	Cash and Cash Equivalents at End of Period	(e)480,175,098	(f)32,723,188

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Other Operating Activities		**Year-to-Date December 2022**
Retail Fuel Cost Under Recovery - Long-Term	$	(1,646,056,735)
Pension, Postretirement, & Other Employee Benefits		(238,137,922)
Asset Retirement Obligation Settlements		(212,361,577)
Return of Utility Scale Solar PPA Collateral		(36,167,915)
Plant Dismantlement Costs Reclassed from Cost of Removal		(29,738,716)
Contract Assets		(26,100,427)
Net (Gain)/Loss on Asset Sales		(17,633,822)
Prepaid Income Taxes - State		(11,979,474)
PPA Performance Security		(8,763,885)
Spent Fuel Dry Cask Storage		(6,597,983)
Transmission Upgrade Charge for PPA		(5,450,000)
SNC Inventory Progress Payments		(4,815,565)
Storm Damage Reserve		83,324,714
Hedge Settlements		31,203,015
Stock Option Expense		13,467,320
Nonaffiliated Storm Assistance Billing		10,844,194
SEGCO Dividends		6,921,949
Distributed Generation Collateral		4,781,802
Other Operating		(908,402)
Total Other Operating Activities	**$**	**(2,094,169,429)**

(b) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Other Investing Activities		**Year-to-Date December 2022**
Nuclear Decommissioning Trust (NDT) Fund Purchases	$	(770,276,049)
Cost of Removal, Net of Salvage		(274,294,367)
Long-Term Service Agreement		(43,841,685)
Non-Utility Property		(37,744,451)
Preliminary Survey and Investigation		(11,802,714)
Prepaid Construction Insurance		(3,029,426)
NDT Fund Sales		758,373,122
Contributions in Aid of Construction		92,452,275
Other Investing		(447,917)
Total Other Investing Activities	**$**	**(290,611,212)**

(c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Other Financing Activities		**Year-to-Date December 2022**
Debt Issuance Costs	$	(24,773,480)
Finance Lease Redemptions		(14,568,782)
Performance Shares Payroll Taxes		(11,278,186)
Total Other Financing Activities	**$**	**(50,620,448)**

(d) Concept: CashAndCashEquivalents

		Year-to-Date December 2021
Supplemental Cash Flow Information		
Cash Paid During the Period for:		
Interest	$	382,389,143
Income Taxes (Net of Refunds)		305,489,375
Noncash Transactions:		
Accrued Property Additions at End of Period	$	478,728,704
Right-of-Use Assets Obtained Under Operating Leases		8,704,288
Right-of-Use Assets Obtained Under Finance Leases		—
Balance Sheet		
Cash (131)	$	32,723,188
Other Special Deposits - Restricted Cash (134)		—
Working Funds (135)		—
Temporary Cash Investments (136)		—
Cash Flow Cash, Cash Equivalents, and Restricted Cash	**$**	**32,723,188**

(e) Concept: CashAndCashEquivalents

		Year-to-Date December 2022
Supplemental Cash Flow Information		
Cash Paid During the Period for:		
Interest	$	432,378,785
Income Taxes (Net of Refunds)		29,666,504
Noncash Transactions:		
Accrued Property Additions at End of Period	$	626,286,409
Right-of-Use Assets Obtained Under Operating Leases		16,755,953
Right-of-Use Assets Obtained Under Finance Leases		115,771,258
Balance Sheet		
Other Special Funds - Restricted Cash (128)	$	55,712,734
Cash (131)		9,462,364
Other Special Deposits - Restricted Cash (134)		60,000,000
Working Funds (135)		—
Temporary Cash Investments (136)		355,000,000
Cash Flow Cash, Cash Equivalents, and Restricted Cash	**$**	**480,175,098**

(f) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Other Operating Activities		Year-to-Date December 2021
Retail Fuel Cost Under Recovery - Long-Term	$	(410,036,834)
Asset Retirement Obligation Settlements		(209,545,950)
Pension, Postretirement, & Other Employee Benefits		(145,730,584)
Plant Dismantlement Costs Reclassed from Cost of Removal		(26,472,247)
SNC Inventory Progress Payments		(6,337,883)
Nonaffiliated Storm Assistance Billing		(5,841,694)
Net (Gain)/Loss on Asset Sales		(3,061,754)
Prepayments		(2,311,624)
Bank Line of Credit Fees		(2,273,405)
Utility Scale Solar PPA Collateral		35,114,639
Stock Option Expense		19,684,246
PPA Cash Performance Security		8,763,885
Contract Assets		8,583,909
SEGCO Dividends		6,880,566
Noncash YTD PS&I Transfers (eliminating net income impact)		6,615,652
Other Operating		1,535,678
Total Other Operating Activities	**$**	**(724,433,400)**

(g) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Other Investing Activities		Year-to-Date December 2021
Nuclear Decommissioning Trust (NDT) Fund Purchases	$	(959,946,471)
Cost of Removal, Net of Salvage		(149,185,132)
Long-Term Service Agreement		(41,923,003)
Preliminary Survey and Investigation		(18,067,046)
Non-Utility Property		(7,644,517)
Prepaid Construction Insurance		(3,912,875)
NDT Fund Sales		955,608,796
Contributions in Aid of Construction		64,740,373
Vogtle 3&4 WEC Receivable		4,029,380
Other Investing		(507,466)
Total Other Investing Activities	**$**	**(156,807,961)**

(h) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Other Financing Activities		Year-to-Date December 2021
Performance Shares Payroll Taxes	$	(10,176,267)
Debt Issuance Costs		(9,615,176)
Other Financing		185,114
Total Other Financing Activities	**$**	**(19,606,329)**

(i) Concept: CashAndCashEquivalents

		Year-to-Date December 2021
Supplemental Cash Flow Information		
Cash Paid During the Period for:		
Interest	$	382,389,143
Income Taxes (Net of Refunds)		305,489,375
Noncash Transactions:		
Accrued Property Additions at End of Period	$	478,728,704
Right-of-Use Assets Obtained Under Operating Leases		8,704,288
Right-of-Use Assets Obtained Under Finance Leases		—
Balance Sheet		
Cash (131)	$	32,723,188
Other Special Deposits - Restricted Cash (134)		—
Working Funds (135)		—
Temporary Cash Investments (136)		—
Cash Flow Cash, Cash Equivalents, and Restricted Cash	**$**	**32,723,188**

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

Notes to the Financial Statements
for
The Southern Company and Subsidiary Companies
Alabama Power Company
Georgia Power Company
Mississippi Power Company
Southern Power Company and Subsidiary Companies
Southern Company Gas and Subsidiary Companies

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Index to Applicable Notes to Financial Statements by Registrant

The following notes to the financial statements are a combined presentation; however, information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf and each Registrant makes no representation as to information related to the other Registrants. The list below indicates the Registrants to which each note applies.

Registrant	Applicable Notes
Southern Company	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16
Alabama Power	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15

Georgia Power	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14
Mississippi Power	1, 2, 3, 4, 5, 6, 8, 9, 10, 11, 12, 13, 14
Southern Power	1, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15
Southern Company Gas	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in the applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States (GAAP). These requirements as they relate to the attached financial statements differ from GAAP primarily in:

- The classification of the components of:
  - Accumulated deferred income taxes
  - Uncertain tax positions
  - Certain miscellaneous current and accrued liabilities
  - Prepaid assets
  - Pension and post-retirement benefit obligations
  - Maturities of long-term debt
  - Deferred debits and credits
  - Certain regulatory assets and liabilities
- The presentation of:
  - Majority-owned subsidiaries and certain other investments
  - Certain other cost of removal obligations
  - Post-retirement defined benefit plans
  - Unamortized debt expense
  - Unamortized discounts for certain short-term debt
  - Taxes applicable to other income and deductions
  - Gains and losses on disposition of property
  - Line of credit commitment fees and associated expenses
  - Certain disallowances on operations and maintenance expenses
  - The fair value amounts of derivative assets and liabilities
  - ASU 2016-02, Leases (Topic 842)
  - ASU 2018-15, Intangibles – Goodwill and Other – Internal-Use Software (Topic 350)
  - ASC 606, Revenue from Contracts with Customers
  - Establishment and/or amortization of regulatory assets and liabilities
  - Assets held for sale
- Comparative presentation

The Notes to the Financial Statements have been prepared in conformity with GAAP. Accordingly, certain Notes are not prepared on the same basis as the financial statements presented herein.

Management has evaluated the impact of events occurring after December 31, 2022 up to February 15, 2023, the date that Georgia Power's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 31, 2023 as it pertains to Georgia Power. These financial statements include all necessary adjustments and disclosures from these evaluations.

General

Southern Company is the parent company of three traditional electric operating companies, as well as Southern Power, Southern Company Gas, SCS, Southern Linc, Southern Holdings, Southern Nuclear, PowerSecure, and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in three Southeastern states. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through natural gas distribution utilities, including Nicor Gas (Illinois), Atlanta Gas Light (Georgia), Virginia Natural Gas, and Chattanooga Gas (Tennessee). Southern Company Gas is also involved in several other complementary businesses including gas pipeline investments and gas marketing services. Prior to the sale of Sequent on July 1, 2021, these businesses also included wholesale gas services. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including Alabama Power's Plant Farley and Georgia Power's Plant Hatch and Plant Vogtle Units 1 and 2, and is currently managing construction and start-up of

Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. PowerSecure develops distributed energy and resilience solutions and deploys microgrids for commercial, industrial, governmental, and utility customers. See Note 15 for information regarding the sale of Sequent.

The Registrants' financial statements reflect investments in subsidiaries on a consolidated basis. Intercompany transactions have been eliminated in consolidation. The equity method is used for investments in entities in which a Registrant has significant influence but does not have control and for VIEs where a Registrant has an equity investment but is not the primary beneficiary. Southern Power has controlling ownership in certain legal entities for which the contractual provisions represent profit-sharing arrangements because the allocations of cash distributions and tax benefits are not based on fixed ownership percentages. For these arrangements, the noncontrolling interest is accounted for under a balance sheet approach utilizing the HLBV method. The HLBV method calculates each partner's share of income based on the change in net equity the partner can legally claim in a HLBV at the end of the period compared to the beginning of the period. See "Variable Interest Entities" herein and Note 7 for additional information.

The traditional electric operating companies, Southern Power, certain subsidiaries of Southern Company Gas, and certain other subsidiaries are subject to regulation by the FERC, and the traditional electric operating companies and the natural gas distribution utilities are also subject to regulation by their respective state PSCs or other applicable state regulatory agencies. As such, the respective financial statements of the applicable Registrants reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by relevant state PSCs or other applicable state regulatory agencies.

The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. These reclassifications had no impact on the Registrants' results of operations, financial position, or cash flows.

Recently Adopted Accounting Standards

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* (ASU 2020-04) providing temporary guidance to ease the potential burden in accounting for reference rate reform primarily resulting from the discontinuation of LIBOR, which began phasing out on December 31, 2021. The discontinuation date of the overnight 1-, 3-, 6-, and 12-month tenors of LIBOR is June 30, 2023, which is beyond the original effective date of ASU 2020-04; therefore, on December 21, 2022, the FASB issued ASU 2022-06, *Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848* (ASU 2022-06) to defer the sunset date of ASU 2020-04 from December 31, 2022 to December 31, 2024.

The amendments are elective and apply to all entities that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued. The guidance (i) simplifies accounting analyses under current GAAP for contract modifications; (ii) simplifies the assessment of hedge effectiveness and allows hedging relationships affected by reference rate reform to continue; and (iii) allows a one-time election to sell or transfer debt securities classified as held to maturity that reference a rate affected by reference rate reform. An entity may elect to apply the amendments prospectively from March 12, 2020 through December 31, 2024 by accounting topic. The Registrants have elected to apply the amendments to modifications of debt and derivative arrangements that meet the scope of ASU 2020-04 and ASU 2022-06.

The Registrants currently reference LIBOR for certain debt and hedging arrangements. In addition, certain provisions in PPAs at Southern Power include references to LIBOR. Contract language has been, or is expected to be, incorporated into each of these agreements to address the transition to an alternative rate for agreements that will be in place at the transition date. No material impacts are expected from modifications to the arrangements and effective hedging relationships are expected to continue. See Note 14 under "Interest Rate Derivatives" for additional information.

Affiliate Transactions

The traditional electric operating companies, Southern Power, and Southern Company Gas have agreements with SCS under which certain of the following services are rendered to them at direct or allocated cost: general executive and advisory, general

and design engineering, operations, purchasing, accounting, finance, tax, legal, information technology, marketing, auditing, insurance and pension administration, human resources, gas, steam

and design engineering, operations, purchasing, accounting, finance, treasury, legal, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, cellular tower space, and other services with respect to business and operations, construction management, and Southern Company power pool transactions. These costs are primarily included in other operations and maintenance expenses or capitalized to property, plant, and equipment. Costs for these services from SCS in 2022, 2021, and 2020 were as follows:

	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)		
2022	$ 549	$ 762	$ 115	$ 86	$ 262
2021	504	663	120	89	239
2020	478	639	149	87	237

Alabama Power and Georgia Power also have agreements with Southern Nuclear under which Southern Nuclear renders the following nuclear-related services at cost: general executive and advisory services; general operations, management, and technical services; administrative services including procurement, accounting, employee relations, systems, and procedures services; strategic planning and budgeting services; other services with respect to business and operations; and, for Georgia Power, construction management. These costs are primarily included in other operations and maintenance expenses or capitalized to property, plant, and equipment. Costs for these services in 2022, 2021, and 2020 amounted to $267 million, $258 million, and $262 million, respectively, for Alabama Power and $895 million, $906 million, and $883 million, respectively, for Georgia Power. See Note 2 under "Georgia Power – Nuclear Construction" for additional information regarding Southern Nuclear's construction management of Plant Vogtle Units 3 and 4 for Georgia Power.

Cost allocation methodologies used by SCS and Southern Nuclear prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

Alabama Power's and Georgia Power's power purchases from affiliates through the Southern Company power pool are included in purchased power, affiliates on their respective statements of income. Mississippi Power's and Southern Power's power purchases from affiliates through the Southern Company power pool are included in purchased power on their respective statements of income and were as follows:

	Mississippi Power	Southern Power
	(in millions)	
2022	$ 4	$ 29
2021	9	15
2020	4	8

Georgia Power has entered into several PPAs with Southern Power for capacity and energy. Georgia Power's total expenses associated with these PPAs were $151 million, $132 million, and $141 million in 2022, 2021, and 2020, respectively. Southern Power's total revenues from all PPAs with Georgia Power, included in wholesale revenue affiliates on Southern Power's consolidated statements of income, were $154 million, $139 million, and $139 million for 2022, 2021, and 2020, respectively. Included within these revenues were affiliate PPAs accounted for as operating leases, which totaled $116 million, $112 million, and $115 million for 2022, 2021, and 2020, respectively. See Note 9 for additional information.

SCS (as agent for Alabama Power, Georgia Power, and Southern Power) and Southern Company Gas have long-term interstate natural gas transportation agreements with SNG that are governed by the terms and conditions of SNG's natural gas tariff and are

subject to FERC regulation. See Note 7 under "Southern Company Gas – Equity Method Investments" for additional information. Transportation costs under these agreements in 2022, 2021, and 2020 were as follows:

	Alabama Power	Georgia Power	Southern Power	Southern Company Gas
		(in millions)		
2022	$ 18	$ 99	$ 37	$ 27
2021	14	108	31	29
2020	15	108	29	29

SCS, as agent for the traditional electric operating companies and Southern Power, has agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. Natural gas purchases made under these agreements were immaterial for Alabama Power, Georgia Power, and Mississippi Power for all periods presented and immaterial, $18 million, and $26 million for Southern Power in 2022, 2021, and 2020, respectively.

Alabama Power and Mississippi Power jointly own Plant Greene County. The companies have an agreement under which Alabama Power operates Plant Greene County and Mississippi Power reimburses Alabama Power for its proportionate share of non-fuel operations and maintenance expenses, which totaled $6 million, $10 million, and $9 million in 2022, 2021, and 2020, respectively. See Note 5 under "Joint Ownership Agreements" for additional information.

Alabama Power, Georgia Power, and Mississippi Power each have agreements with PowerSecure for equipment purchases and/or services related to utility infrastructure construction, distributed energy, and energy efficiency projects. Costs under these agreements were immaterial for all periods presented.

In 2022, Southern Company Gas entered into a $70 million contract with the U.S. General Services Administration to increase energy efficiency at certain federal buildings across Georgia, with completion expected to occur in 2024. Southern Company Gas engaged PowerSecure to provide the majority of the construction services under the contract. During 2022, Southern Company Gas paid $10 million to PowerSecure related to this agreement.

See Note 7 under "SEGCO" for information regarding Alabama Power's and Georgia Power's equity method investment in SEGCO and related affiliate purchased power costs, as well as Alabama Power's gas pipeline ownership agreement with SEGCO.

Southern Power has several agreements with SCS for transmission services, which are billed to Southern Power based on the Southern Company Open Access Transmission Tariff as filed with the FERC. Transmission services purchased by Southern Power from SCS totaled $39 million, $28 million, and $15 million for 2022, 2021, and 2020, respectively, and were charged to other operations and maintenance expenses in Southern Power's consolidated statements of income.

The traditional electric operating companies and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 14 under "Contingent Features" for additional information. Southern Power and the traditional electric operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity. See "Revenues – Southern Power" herein for additional information.

The traditional electric operating companies, Southern Power, and Southern Company Gas provide incidental services to and receive such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the traditional electric operating companies, Southern Power, and Southern Company Gas neither provided nor received any material services to or from affiliates in any year presented.

Regulatory Assets and Liabilities

The traditional electric operating companies and the natural gas distribution utilities are subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent costs recovered that are expected to

be incurred in the future or probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

In the event that a portion of a traditional electric operating company's or a natural gas distribution utility's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to AOCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional electric operating company or the natural gas distribution utility would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their

electric operating company or the natural gas distribution utility would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 2 for additional information including details of regulatory assets and liabilities reflected in the balance sheets for Southern Company, the traditional electric operating companies, and Southern Company Gas.

Revenues

The Registrants generate revenues from a variety of sources which are accounted for under various revenue accounting guidance, including revenue from contracts with customers, lease, derivative, and regulatory accounting. See Notes 4, 9, and 14 for additional information.

Traditional Electric Operating Companies

The majority of the revenues of the traditional electric operating companies are generated from contracts with retail electric customers. These revenues, generated from the integrated service to deliver electricity when and if called upon by the customer, are recognized as a single performance obligation satisfied over time, at a tariff rate, and as electricity is delivered to the customer during the month. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Retail rates may include provisions to adjust revenues for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered from or returned to customers, respectively, through adjustments to the billing factors. See Note 2 for additional information regarding regulatory matters of the traditional electric operating companies.

Wholesale capacity revenues from PPAs are recognized in amounts billable under the contract terms. Energy and other revenues are generally recognized as services are provided. The contracts for capacity and energy in a wholesale PPA have multiple performance obligations where the contract's total transaction price is allocated to each performance obligation based on the standalone selling price. The standalone selling price is primarily determined by the price charged to customers for the specific goods or services transferred with the performance obligations. Generally, the traditional electric operating companies recognize revenue as the performance obligations are satisfied over time as electricity is delivered to the customer or as generation capacity is available to the customer.

For both retail and wholesale revenues, the traditional electric operating companies have elected to recognize revenue for their sales of electricity and capacity using the invoice practical expedient as they generally have a right to consideration in an amount that corresponds directly with the value to the customer of the performance completed to date and that may be invoiced. Payment for goods and services rendered is typically due in the subsequent month following satisfaction of the Registrants' performance obligation.

Southern Power

Southern Power sells capacity and energy at rates specified under contractual terms in long-term PPAs. These PPAs are accounted for as leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Energy revenues are recognized in the period the energy is delivered. Capacity revenues from PPAs classified as sales-type leases are recognized by accounting for interest income on the net investment in the lease.

Southern Power's non-lease contracts commonly include capacity and energy which are considered separate performance obligations. In these contracts, the total transaction price is allocated to each performance obligation based on the standalone selling price. The standalone selling price is primarily determined by the price charged to customers for the specific goods or

services transferred with the performance obligations. Generally, Southern Power recognizes revenue as the performance obligations are satisfied over time, as electricity is delivered to the customer or as generation capacity is made available to the customer.

Southern Power generally has a right to consideration in an amount that corresponds directly with the value to the customer of the performance completed to date and may recognize revenue in the amount to which the entity has a right to invoice. Payment for goods and services rendered is typically due in the subsequent month following satisfaction of Southern Power's performance obligation.

When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements.

Southern Power may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains and losses on such contracts are recorded in wholesale revenues. See Note 14 and "Financial Instruments" herein for additional information.

Southern Company Gas

Gas Distribution Operations

Southern Company Gas records revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory agencies of the natural gas distribution utilities. Atlanta Gas Light operates in a deregulated natural gas market whereby Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. As required by the Georgia PSC, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial, and industrial end-use customer's distribution costs as well as for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable charge, which reflects the historic volumetric usage pattern for the entire residential class.

The majority of the revenues of Southern Company Gas are generated from contracts with natural gas distribution customers. Revenues from this integrated service to deliver gas when and if called upon by the customer are recognized as a single performance obligation satisfied over time and are recognized at a tariff rate as gas is delivered to the customer during the month.

The standalone selling price is primarily determined by the price charged to customers for the specific goods or services transferred with the performance obligations. Generally, Southern Company Gas recognizes revenue as the performance obligations are satisfied over time as natural gas is delivered to the customer. The performance obligations related to wholesale gas services are satisfied, and revenue is recognized, at a point in time when natural gas is delivered to the customer.

Southern Company Gas has elected to recognize revenue for sales of gas using the invoice practical expedient as it generally has a right to consideration in an amount that corresponds directly with the value to the customer of the performance completed to date and that may be invoiced. Payment for goods and services rendered is typically due in the subsequent month following satisfaction of Southern Company Gas' performance obligation.

With the exception of Atlanta Gas Light, the natural gas distribution utilities have rate structures that include volumetric rate designs that allow the opportunity to recover certain costs based on gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. For other commercial and industrial customers, revenues are based on actual deliveries through the end of the period.

The tariffs for the natural gas distribution utilities include provisions which allow for the recognition of certain revenues prior to the time such revenues are billed to customers. These provisions are referred to as alternative revenue programs and provide for the recognition of certain revenues prior to billing, as long as the amounts recognized will be collected from customers within 24

months of recognition. Revenue related to alternative revenue programs was $(5) million, $11 million, and $3 million in 2022, 2021, and 2020, respectively. These programs are as follows:

- *Weather normalization adjustments* – reduce customer bills when winter weather is colder than normal and increase customer bills when weather is warmer than normal and are included in the tariffs for Virginia Natural Gas and Chattanooga Gas;
- *Revenue normalization mechanisms* – mitigate the impact of conservation and declining customer usage and are contained in the tariffs for Virginia Natural Gas and Nicor Gas; and
- *Revenue true-up adjustment* – included within the provisions of the GRAM program in which Atlanta Gas Light participates as a short-term alternative to formal rate case filings, the revenue true-up feature provides for a positive (or negative) adjustment to record revenue in the amount of any variance to budgeted revenues, which are submitted and approved annually as a requirement of GRAM. Such adjustments are reflected in customer billings in a subsequent program year.

Wholesale Gas Services

Prior to the sale of Sequent on July 1, 2021, Southern Company Gas netted revenues from energy and risk management activities with the associated costs. Profits from sales between segments were eliminated and recognized as goods or services sold to end-use customers. Southern Company Gas recorded wholesale gas services' transactions that qualified as derivatives at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes were presented on a net basis in revenue. See Note 15 under "Southern Company Gas" for additional information on the sale of Sequent.

Gas Marketing Services

Southern Company Gas recognizes revenues from natural gas sales and transportation services in the same period in which the related volumes are delivered to customers and recognizes sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. Southern Company Gas also recognizes unbilled revenues for estimated deliveries of gas not

yet billed to these customers from the most recent meter reading date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries during the period.

Southern Company Gas recognizes revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts.

Concentration of Revenue

Southern Company, Alabama Power, Georgia Power, Mississippi Power (with the exception of its full requirements cost-based MRA electric tariffs described below), Southern Power, and Southern Company Gas each have a diversified base of customers and no single customer or industry comprises 10% or more of each company's revenues.

Mississippi Power provides service under long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under requirements cost-based MRA electric tariffs, which are subject to regulation by the FERC. The contracts with these wholesale customers represented 12.4% of Mississippi Power's total operating revenues in 2022. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Fuel Costs

Fuel costs for the traditional electric operating companies and Southern Power are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. For Alabama Power and Georgia Power, fuel expense also includes the amortization of the cost of nuclear fuel. For the traditional electric operating companies, fuel costs also include gains and/or losses from fuel-hedging programs as approved by their respective state PSCs.

Cost of Natural Gas

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, Southern Company Gas charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently-incurred natural gas costs are passed through to customers without markup, subject to regulatory review. Southern Company Gas defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period such that no operating income is recognized related to these costs. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred and accrued natural gas costs are included in the balance sheets as regulatory assets and regulatory liabilities, respectively.

Southern Company Gas' gas marketing services' customers are charged for actual or estimated natural gas consumed. Within cost of natural gas, Southern Company Gas also includes costs of lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives.

Income Taxes

The Registrants use the liability method of accounting for deferred income taxes and provide deferred income taxes for all significant income tax temporary differences. In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies are amortized over the average life of the related property, with such amortization normally applied as a credit to reduce depreciation and amortization in the statements of income. Southern Power's and the natural gas distribution utilities' deferred federal ITCs, as well as certain state ITCs for Nicor Gas, are amortized to income tax expense over the life of the respective asset.

Under current tax law, certain projects at Southern Power related to the construction of renewable facilities are eligible for federal ITCs. Southern Power estimates eligible costs which, as they relate to acquisitions, may not be finalized until the allocation of the purchase price to assets has been finalized. Southern Power applies the deferred method to ITCs, whereby the ITCs are recorded as a deferred credit and amortized to income tax expense over the life of the respective asset. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. State ITCs are recognized as an income tax benefit in the period in which the credits are generated. In addition, certain projects are eligible for federal and state PTCs, which are recognized as an income tax benefit based on KWH production.

Federal ITCs and PTCs, as well as state ITCs and other state tax credits available to reduce income taxes payable, were not fully utilized in 2022 and will be carried forward and utilized in future years. In addition, Southern Company is expected to have various state net operating loss (NOL) carryforwards for certain of its subsidiaries, including Mississippi Power and Southern Power, which would result in income tax benefits in the future, if utilized. See Note 10 under "Current and Deferred Income Taxes – Tax Credit Carryforwards" and " – Net Operating Loss Carryforwards" for additional information.

The Registrants recognize tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 10 under "Unrecognized Tax Benefits" for additional information.

Other Taxes

Taxes imposed on and collected from customers on behalf of governmental agencies are presented net on the Registrants' statements of income and are excluded from the transaction price in determining the revenue related to contracts with a customer.

Southern Company Gas is taxed on its gas revenues by various governmental authorities, but is allowed to recover these taxes from its customers. Revenue taxes imposed on the natural gas distribution utilities are recorded at the amount charged to customers, which may include a small administrative fee, as operating revenues, and the related taxes imposed on Southern Company Gas are recorded as operating expenses on the statements of income. Revenue taxes included in operating expenses were $158 million, $119 million, and $104 million in 2022, 2021, and 2020, respectively.

Allowance for Funds Used During Construction and Interest Capitalized

The traditional electric operating companies and the natural gas distribution utilities record AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the asset through a higher rate base and higher depreciation. The equity component of AFUDC is not taxable.

Interest related to financing the construction of new facilities at Southern Power and new facilities not included in the traditional electric operating companies' and Southern Company Gas' regulated rates is capitalized in accordance with standard interest capitalization requirements.

Total AFUDC and interest capitalized for the Registrants in 2022, 2021, and 2020 was as follows:

	Southern Company	Alabama Power	Georgia Power(*)	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022	$ 327	$ 90	$ 213	$ —	$ —	$ 24
2021	282	68	190	—	6	18
2020	230	61	138	1	11	18

* See Note 2 under "Georgia Power – Nuclear Construction" for information on the inclusion of a portion of construction costs related to Plant Vogtle Units 3 and 4 in Georgia Power's rate base.

The average AFUDC composite rates for 2022, 2021, and 2020 for the traditional electric operating companies and the natural gas distribution utilities were as follows:

	2022	2021	2020
Alabama Power	7.9 %	7.9 %	8.1 %
Georgia Power(*)	7.3 %	7.2 %	6.9 %
Mississippi Power	5.3 %	2.5 %	5.4 %
Southern Company Gas:			
Atlanta Gas Light	7.6 %	7.7 %	7.7 %
Chattanooga Gas	7.1 %	7.1 %	7.1 %
Nicor Gas	2.0 %	0.1 %	0.7 %

* Excludes AFUDC related to the construction of Plant Vogtle Units 3 and 4. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

Impairment of Long-Lived Assets

The Registrants evaluate long-lived assets and finite-lived intangible assets for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance, a sales transaction price that is less than the asset group's carrying amount, or an estimate of undiscounted future cash flows attributable to the asset group, as compared with the carrying amount of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying amount is greater than the fair value. For assets identified as held for sale, the carrying amount is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Notes 7 and 9 under "Southern Company Gas" and "Southern Company Leveraged Lease," respectively, and Note 15 under "Southern Company" and "Southern Company Gas" for information regarding impairment charges recorded during the periods presented.

Goodwill and Other Intangible Assets and Liabilities

Southern Power's intangible assets consist primarily of certain PPAs acquired, which are amortized over the term of the respective PPA. Southern Company Gas' goodwill and other intangible assets and liabilities primarily relate to its 2016 acquisition by Southern Company. In addition to these items, Southern Company's goodwill and other intangible assets also relate to its 2016 acquisition of PowerSecure.

For its 2022 and 2020 annual impairment tests, Southern Company Gas management performed the qualitative assessment and determined that it was more likely than not that the fair value of all of its reporting units with goodwill exceeded their carrying amounts, and therefore no quantitative assessment was required. For its 2021 annual impairment test, Southern Company Gas management performed the quantitative assessment and confirmed that the fair values of all of its reporting units with goodwill exceeded their carrying amounts.

For its 2021 and 2020 annual impairment tests, PowerSecure management performed the quantitative assessment, which resulted in the fair value of PowerSecure exceeding its carrying amount. For its 2022 annual impairment test, PowerSecure management performed the quantitative assessment, which resulted in the fair value of PowerSecure being lower than its carrying amount. The fair value was estimated using a discounted cash flow analysis. The decline in fair value primarily resulted from declining macroeconomic conditions, reducing sales growth and estimated cash flows. As a result, a goodwill impairment of $119 million was recorded in the fourth quarter 2022. The worldwide disruptions in supply chain, reduced labor availability and productivity, and reduced economic activity in the United States have had a variety of adverse impacts on Southern Company and its subsidiaries, including PowerSecure. If these factors continue to negatively affect the operating results of PowerSecure, all or a portion of its remaining goodwill of $144 million may become impaired.

At December 31, 2022 and 2021, goodwill was as follows:

	At December 31, 2022	At December 31, 2021
	(in millions)	
Southern Company	$ 5,161	$ 5,280
Southern Company Gas:		
Gas distribution operations	$ 4,034	$ 4,034
Gas marketing services	981	981
Southern Company Gas total	$ 5,015	$ 5,015

At December 31, 2022 and 2021, other intangible assets were as follows:

	At December 31, 2022			At December 31, 2021		
	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
		(in millions)			*(in millions)*	
Southern Company						
Subject to amortization:						
Customer relationships	$ 212	$ (162)	$ 50	$ 212	$ (150)	$ 62
Trade names	64	(44)	20	64	(38)	26
PPA fair value adjustments	390	(129)	261	390	(109)	281
Other	5	(5)	—	11	(10)	1
Total subject to amortization	$ 671	$ (340)	$ 331	$ 677	$ (307)	$ 370
Not subject to amortization:						
FCC licenses	75	—	75	75	—	75
Total other intangible assets	$ 746	$ (340)	$ 406	$ 752	$ (307)	$ 445
Southern Power[*]						
PPA fair value adjustments	$ 390	$ (129)	$ 261	$ 390	$ (109)	$ 281
Southern Company Gas[*]						
Gas marketing services						
Customer relationships	$ 156	$ (139)	$ 17	$ 156	$ (130)	$ 26
Trade names	26	(17)	9	26	(15)	11
Total other intangible assets	$ 182	$ (156)	$ 26	$ 182	$ (145)	$ 37

* All subject to amortization.

Amortization associated with other intangible assets in 2022, 2021, and 2020 was as follows:

	2022	2021	2020
		(in millions)	
Southern Company[a]	**$ 39**	$ 44	$ 49
Southern Power[b]	**20**	20	20
Southern Company Gas:			
Gas marketing services	**$ 11**	$ 15	$ 17
Wholesale gas services[b]	**—**	—	2
Southern Company Gas total	**$ 11**	$ 15	$ 19

(a) Includes $20 million, $20 million, and $22 million in 2022, 2021, and 2020, respectively, recorded as a reduction to operating revenues.

(b) Recorded as a reduction to operating revenues.

At December 31, 2022, the estimated amortization associated with other intangible assets for the next five years is as follows:

2023	2024	2025	2026	2027
		(in millions)		

Southern Company	$ 36	$ 35	$ 31	$ 26	$ 23
Southern Power	20	20	20	20	20
Southern Company Gas	9	8	6	3	—

Acquisition Accounting

At the time of an acquisition, management will assess whether acquired assets and activities meet the definition of a business. Acquisitions that meet the definition of a business are accounted for under the acquisition method, and operating results from the date of acquisition are included in the acquiring entity's financial statements. The purchase price, including any contingent consideration, is allocated based on the fair value of the identifiable assets acquired and liabilities assumed (including any intangible assets). Assets acquired that do not meet the definition of a business are accounted for as an asset acquisition. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired.

Determining the fair value of assets acquired and liabilities assumed requires management judgment and management may engage independent valuation experts to assist in this process. Fair values are determined by using market participant assumptions and typically include the timing and amounts of future cash flows, incurred construction costs, the nature of acquired contracts, discount rates, power market prices, and expected asset lives. Any due diligence or transition costs incurred for potential or successful acquisitions are expensed as incurred.

Historically, contingent consideration primarily relates to fixed amounts due to the seller once an acquired construction project is placed in service. For contingent consideration with variable payments, management fair values the arrangement with any changes recorded in the statements of income. See Note 13 for additional fair value information.

Development Costs

For Southern Power, development costs are capitalized once a project is probable of completion, primarily based on a review of its economics and operational feasibility, as well as the status of power off-take agreements and regulatory approvals, if applicable. Southern Power's capitalized development costs are included in CWIP on the balance sheets. All of Southern Power's development costs incurred prior to the determination that a project is probable of completion are expensed as incurred and included in other operations and maintenance expense in the statements of income. If it is determined that a project is no longer probable of completion, any of Southern Power's capitalized development costs are expensed and included in other operations and maintenance expense in the statements of income.

Long-Term Service Agreements

The traditional electric operating companies and Southern Power have entered into LTSAs for the purpose of securing maintenance support for certain of their generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs for the performance of any planned inspections or unplanned capital maintenance are recorded in the statements of cash flows as investing activities. Receipts of major parts into materials and supplies inventory prior to planned inspections are treated as noncash transactions in the statements of cash flows. Any payments made prior to the work being performed are recorded as prepayments in other current assets and noncurrent assets on the balance sheets. At the time work is performed, an appropriate amount is accrued for future payments or transferred from the prepayment and recorded as property, plant, and equipment or expensed.

Transmission Receivables/Prepayments

As a result of Southern Power's acquisition and construction of generating facilities, Southern Power has transmission receivables and/or prepayments representing the portion of interconnection network and transmission upgrades that will be reimbursed to Southern Power. Upon completion of the related project, transmission costs are generally reimbursed by the interconnection provider within a five-year period and the receivable/prepayments are reduced as payments or services are received.

Cash, Cash Equivalents, and Restricted Cash

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets that total to the amount shown in the statements of cash flows for the applicable Registrants:

	Southern Company		Georgia Power	Southern Power		Southern Company Gas	
	December 31,						
	2022	2021	2022	2022	2021	2022	2021
	(in millions)			*(in millions)*		*(in millions)*	
Cash and cash equivalents	$ 1,917	$ 1,798	$ 364	$ 131	$ 107	$ 81	$ 45
Restricted cash[(a)]:							
Other current assets	62	2	60	—	—	2	2
Other deferred charges and assets	58	29	56	3	29	—	—
Total cash, cash equivalents, and restricted cash[(b)]	$ 2,037	$ 1,829	$ 480	$ 133	$ 135	$ 83	$ 48

(a) For Georgia Power, reflects proceeds from the issuance of solid waste disposal facility revenue bonds. See Note 8 under "Long-term Debt" for additional information. Georgia Power did not have any restricted cash at December 31, 2021. For Southern Power, reflects $3 million and $10 million at December 31, 2022 and 2021, respectively, held to fund estimated construction completion costs at the Deuel Harvest wind facility and $19 million at December 31, 2021 related to tax equity contributions restricted until the Garland battery energy storage facility achieved final contracted capacity. See Note 15 under "Southern Power" for additional information. For Southern Company Gas, reflects collateral for workers' compensation, life insurance, and long-term disability insurance.

(b) Total may not add due to rounding.

Storm Damage and Reliability Reserves

Each traditional electric operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution lines and, for Mississippi Power, the cost of uninsured damages to its generation facilities and other property. Alabama Power also has authority from the Alabama PSC to accrue certain additional amounts as circumstances warrant. Alabama Power recorded additional accruals of $65 million and $100 million in 2021 and 2020, respectively, which are included in the table below. In accordance with their respective state PSC orders, the traditional electric operating companies accrued the following amounts related to storm damage recovery in 2022, 2021, and 2020:

	Southern Company[(*)]	Alabama Power	Georgia Power	Mississippi Power[(*)]
		(in millions)		
2022	$ 239	$ 19	$ 213	$ 7
2021	286	75	213	(2)
2020	326	112	213	1

* Mississippi Power's net accrual includes carrying costs, as well as amortization of related excess deferred income tax benefits.

In 2022, costs for weather-related damages charged against storm damage reserves totaled $24 million and $82 million for Alabama Power and Georgia Power, respectively, and were immaterial for Mississippi Power. See Note 2 under "Alabama Power – Rate NDR," "Georgia Power – Storm Damage Recovery," and "Mississippi Power – System Restoration Rider" for additional information regarding each company's storm damage reserve.

During 2022, the Alabama PSC and the Mississippi PSC authorized Alabama Power and Mississippi Power, respectively, to make accruals to a reliability reserve if certain conditions are met. During 2022, Alabama Power and Mississippi Power accrued the following amounts to their reliability reserves:

	Southern Company	Alabama Power	Mississippi Power

		(in millions)	
2022	$ 191	$ 166	$ 25

See Note 2 under "Alabama Power – Reliability Reserve Accounting Order" and "Mississippi Power – Reliability Reserve Accounting Order" for additional information.

Materials and Supplies

Materials and supplies for the traditional electric operating companies generally includes the average cost of transmission, distribution, and generating plant materials. Materials and supplies for Southern Company Gas generally includes propane gas inventory, liquefied natural gas inventory, fleet fuel, and other materials and supplies. Materials and supplies for Southern Power generally includes the average cost of generating plant materials.

Materials are recorded to inventory when purchased and then expensed or capitalized to property, plant, and equipment, as appropriate, at weighted average cost when installed. In addition, certain major parts are recorded as inventory when acquired and then capitalized at cost when installed to property, plant, and equipment.

Fuel Inventory

Fuel inventory for the traditional electric operating companies includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel inventory for Southern Power, which is included in other current assets, includes the average cost of oil, natural gas, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used. Emissions allowances granted by the EPA are included in inventory at zero cost. The traditional electric operating companies recover fuel expense through fuel cost recovery rates approved by each state PSC or, for wholesale rates, the FERC.

Natural Gas for Sale

With the exception of Nicor Gas, Southern Company Gas records natural gas inventories on a WACOG basis. In Georgia's deregulated, competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. On a monthly basis, Atlanta Gas Light assigns to Marketers the majority of the pipeline storage services that it has under contract, along with a corresponding amount of inventory. Atlanta Gas Light retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand.

Nicor Gas' natural gas inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. The cost of natural gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on Southern Company's or Southern Company Gas' net income. At December 31, 2022, the Nicor Gas LIFO inventory balance was $170 million. Based on the average cost of gas purchased in December 2022, the estimated replacement cost of Nicor Gas' inventory at December 31, 2022 was $613 million.

Southern Company Gas' gas marketing services and all other segments record inventory at LOCOM, with cost determined on a WACOG basis. For these segments, Southern Company Gas evaluates the weighted average cost of its natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, Southern Company Gas records LOCOM adjustments to cost of natural gas to reduce the value of its natural gas inventories to market value. LOCOM adjustments were immaterial for all periods presented.

Provision for Uncollectible Accounts

The customers of the traditional electric operating companies and the natural gas distribution utilities are billed monthly. For the majority of receivables, a provision for uncollectible accounts is established based on historical collection experience and other factors. For the remaining receivables, if the company is aware of a specific customer's inability to pay, a provision for uncollectible accounts is recorded to reduce the receivable balance to the amount reasonably expected to be collected. If circumstances change, the estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect this estimate include, but are not limited to, customer credit issues, customer deposits, and general economic conditions.

Customers' accounts are written off once they are deemed to be uncollectible. For all periods presented, uncollectible accounts averaged less than 1% of revenues for each Registrant.

Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year.

Concentration of Credit Risk

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 14 Marketers in Georgia (including SouthStar). The credit risk exposure to the Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain credit security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Financial Instruments

The traditional electric operating companies and Southern Power use derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. Southern Company Gas uses derivative financial instruments to limit exposure to fluctuations in natural gas prices, weather, interest rates, and commodity prices. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 13 for additional information regarding fair value. Substantially all of the traditional electric operating companies' and Southern Power's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional electric operating companies' and the natural gas distribution utilities' fuel-hedging programs result in the deferral of related gains and losses in AOCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 14 for additional information regarding derivatives.

The Registrants offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. The Registrants had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2022.

The Registrants are exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Registrants have established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate their exposure to counterparty credit risk.

Southern Company Gas

Southern Company Gas enters into weather derivative contracts as economic hedges of natural gas revenues in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in natural gas revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are also reflected in natural gas revenues in the statements of income.

Southern Company Gas enters into transactions to secure transportation capacity between delivery points in order to serve its customers and various markets. NYMEX futures and OTC contracts are used to capture the price differential or spread between the locations served by the capacity to substantially protect the natural gas revenues that will ultimately be realized when the physical flow of natural gas between delivery points occurs. These contracts generally meet the definition of derivatives and are

carried at fair value on the balance sheets, with changes in fair value included in earnings in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage, and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis utilized for the derivatives used to mitigate the natural gas price risk associated with the storage and transportation portfolio. Monthly demand charges are incurred for the contracted storage and transportation capacity and payments associated with asset management agreements, and these demand charges and payments are recognized on the statements of income in the period they are incurred. This difference in accounting methods can result in volatility in reported earnings, even though the economic margin is substantially unchanged from the dates the transactions were consummated.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income attributable to the Registrant, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts

included in net income. Comprehensive income also consists of certain changes in pension and other postretirement benefit plans for Southern Company, Southern Power, and Southern Company Gas.

AOCI (loss) balances, net of tax effects, for Southern Company, Southern Power, and Southern Company Gas were as follows:

	Qualifying Hedges	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)(*)
		(in millions)	
Southern Company			
Balance at December 31, 2021	$ (162)	$ (76)	$ (237)
Current period change	13	58	71
Balance at December 31, 2022	**$ (149)**	**$ (18)**	**$ (167)**
Southern Power			
Balance at December 31, 2021	$ 1	$ (29)	$ (27)
Current period change	(10)	20	10
Balance at December 31, 2022	**$ (9)**	**$ (9)**	**$ (18)**
Southern Company Gas			
Balance at December 31, 2021	$ (14)	$ 38	$ 24
Current period change	(11)	18	7
Balance at December 31, 2022	**$ (25)**	**$ 56**	**$ 31**

* May not add due to rounding.

Variable Interest Entities

The Registrants may hold ownership interests in a number of business ventures with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE. The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. See Note 7 for additional information regarding VIEs.

2. REGULATORY MATTERS

Regulatory Assets and Liabilities

Details of regulatory assets and (liabilities) reflected in the balance sheets at December 31, 2022 and 2021 are provided in the following tables:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
At December 31, 2022					
AROs[(a)(u)]	$ 6,096	$ 1,971	$ 3,829	$ 242	$ —
Retiree benefit plans[(b)(u)]	2,517	675	848	113	114
Remaining net book value of retired assets[(c)]	1,543	562	962	19	—
Under recovered regulatory clause revenues[(d)]	953	788	—	31	134
Deferred income tax charges[(e)]	866	250	583	30	—
Environmental remediation[(f)(u)]	294	—	25	—	269
Loss on reacquired debt[(g)]	257	38	213	5	1
Vacation pay[(h)(u)]	212	82	108	10	12
Regulatory clauses[(i)]	142	142	—	—	—
Software and cloud computing costs[(j)]	111	46	59	—	6
Nuclear outage[(k)]	82	52	30	—	—
Long-term debt fair value adjustment[(l)]	69	—	—	—	69
Fuel-hedging (realized and unrealized) losses[(m)]	60	15	45	—	—
Storm damage[(n)]	44	—	—	44	—
Plant Daniel Units 3 and 4[(o)]	27	—	—	27	—
Kemper County energy facility assets, net[(p)]	20	—	—	20	—
Other regulatory assets[(q)]	197	36	27	16	118
Deferred income tax credits[(e)]	(5,251)	(1,925)	(2,244)	(269)	(788)
Other cost of removal obligations[(a)]	(1,430)	11	462	(196)	(1,707)
Storm/property damage reserves[(r)]	(216)	(97)	(83)	(36)	—
Reliability reserves[(r)]	(191)	(166)	—	(25)	—
Customer refunds[(s)]	(183)	(62)	(121)	—	—
Fuel-hedging (realized and unrealized) gains[(m)]	(83)	(38)	(21)	(24)	—
Over recovered regulatory clause revenues[(d)]	(64)	—	(38)	—	(26)
Other regulatory liabilities[(t)]	(239)	(40)	(21)	(3)	(93)
Total regulatory assets (liabilities), net	$ 5,833	$ 2,340	$ 4,663	$ 4	$ (1,891)
At December 31, 2021					
AROs[(a)(u)]	$ 5,685	$ 1,576	$ 3,866	$ 236	$ —
Retiree benefit plans[(b)(u)]	2,998	747	962	145	95
Remaining net book value of retired assets[(c)]	1,050	574	455	21	—
Deferred income tax charges[(e)]	829	240	555	31	—
Under recovered regulatory clause revenues[(d)]	806	225	—	49	532
Environmental remediation[(f)(u)]	302	—	35	—	267
Loss on reacquired debt[(g)]	281	42	231	6	2
Vacation pay[(h)(u)]	207	81	102	10	14

Vacation pay[h]	207	81	102	10	14
Regulatory clauses[i]	142	142	—	—	—
Storm damage[n]	97	—	48	49	—
Long-term debt fair value adjustment[l]	79	—	—	—	79
Nuclear outage[k]	75	41	34	—	—
Software and cloud computing costs[j]	73	35	33	—	5
Kemper County energy facility assets, net[p]	35	—	—	35	—
Plant Daniel Units 3 and 4[o]	28	—	—	28	—
Other regulatory assets[q]	168	38	29	7	94
Deferred income tax credits[e]	(5,636)	(1,968)	(2,537)	(288)	(816)
Other cost of removal obligations[a]	(1,826)	(192)	278	(195)	(1,683)
Customer refunds[s]	(189)	(181)	(8)	—	—
Fuel-hedging (realized and unrealized) gains[m]	(176)	(50)	(72)	(54)	—
Storm/property damage reserves[r]	(133)	(103)	—	(30)	—
Over recovered regulatory clause revenues[d]	(63)	(1)	(59)	—	(3)
Other regulatory liabilities[t]	(121)	(29)	(24)	(4)	(57)
Total regulatory assets (liabilities), net	$ 4,711	$ 1,217	$ 3,928	$ 46	$ (1,471)

Unless otherwise noted, the following recovery and amortization periods for these regulatory assets and (liabilities) have been approved by the respective state PSC or regulatory agency:

(a) AROs and other cost of removal obligations generally are recorded over the related property lives, which may range up to 53 years for Alabama Power, 57 years for Georgia Power, 55 years for Mississippi Power, and 80 years for Southern Company Gas. AROs and cost of removal obligations are settled and trued up following completion of the related activities. Alabama Power is recovering CCR ARO expenditures over a 38-year period ending in 2054 through Rate CNP Compliance. Effective January 1, 2023, Georgia Power is recovering CCR ARO expenditures over four-year periods through its ECCR tariff. Prior to 2023, expenditures were recovered over three-year periods. See "Georgia Power – Rate Plans" herein and Note 6 for additional information.

(b) Recovered and amortized over the average remaining service period, which may range up to 13 years for Alabama Power, Georgia Power, and Mississippi Power and up to 14 years for Southern Company Gas. Southern Company's balances also include amounts at SCS and Southern Nuclear that are allocated to the applicable regulated utilities. See Note 11 for additional information.

(c) Alabama Power: Primarily represents the net book value of Plant Gorgas Units 8, 9, and 10 ($492 million at December 31, 2022) being amortized over remaining periods not exceeding 15 years (through 2037). Balance at December 31, 2022 also includes approximately $42 million related to Plant Barry Unit 4 being amortized over the unit's remaining useful life (through 2034). See "Alabama Power – Environmental Accounting Order" herein for additional information.

Georgia Power: Net book values of Plant Wansley Units 1 and 2 (totaling $562 million at December 31, 2022) are being amortized over a remaining period of eight years (through 2030) and net book values of Plant Hammond Units 1 through 4 and Plant Branch Units 3 and 4 (totaling $396 million at December 31, 2022) are being amortized over remaining periods of between one and 13 years (between 2023 and 2035). Balance at December 31, 2022 also includes unusable materials and supplies inventories, as discussed further under "Georgia Power – Integrated Resource Plans" herein.

Mississippi Power: Represents net book value of certain environmental compliance assets at Plant Watson and Plant Greene County. The retail portion is being amortized over a 10-year period through 2030 and the wholesale portion is being amortized over a 14-year period through 2035. See "Mississippi Power – Environmental Compliance Overview Plan" herein for additional information.

(d) Alabama Power: Balances are recorded monthly and expected to be recovered over periods of up to eight years, with the majority expected to be recovered within two years. See "Alabama Power – Rate CNP PPA," " – Rate CNP Compliance," and " – Rate ECR" herein for additional information.

Georgia Power: Balances are recorded monthly and expected to be recovered or returned within two years. See "Georgia Power – Rate Plans" herein for additional information.

Mississippi Power: At December 31, 2022, $12 million is being amortized over a three-year period ending in 2023 and the remaining $18 million is expected to be recovered through various rate recovery mechanisms over a period to be determined in future rate filings. See "Mississippi Power – Ad Valorem Tax Adjustment" herein for additional information.

Southern Company Gas: Balances are recorded and recovered or amortized over periods generally not exceeding five years. In addition to natural gas cost recovery mechanisms, the natural gas distribution utilities have various other cost recovery mechanisms for the recovery of costs, including those related to infrastructure replacement programs.

(e) Deferred income tax charges are recovered and deferred income tax credits are amortized over the related property lives, which may range up to 53 years for Alabama Power, 57 years for Georgia Power, 55 years for Mississippi Power, and 80 years for Southern Company Gas. See Note 10 for additional information. As a result of the Tax Reform Legislation, these accounts include certain deferred income tax assets and liabilities not subject to normalization, as described further below:

Alabama Power: Related amounts at December 31, 2022 include excess federal deferred income tax liabilities that are being returned to customers through bill credits of up to approximately $318 million in 2023, as discussed under "Alabama Power – Excess Accumulated Deferred Income Tax Accounting Order" herein. The Alabama PSC will determine the treatment of any remaining excess federal accumulated deferred income taxes at a future date. Remaining amounts are being recovered and amortized ratably over the related property lives.

Georgia Power: Related amounts at December 31, 2022 include $145 million of deferred income tax assets related to CWIP for Plant Vogtle Units 3 and 4, the recovery of which is expected to be determined in a future regulatory proceeding.

Mississippi Power: Related amounts at December 31, 2022 include $33 million of retail deferred income tax liabilities generally being amortized over three years through 2025.

Southern Company Gas: Related amounts at December 31, 2022 include $1 million of deferred income tax liabilities being amortized through 2024. See "Southern Company Gas – Rate Proceedings" herein for additional information.

(f) Effective January 1, 2023, Georgia Power is recovering $5 million annually for environmental remediation under the 2022 ARP. Southern Company Gas' costs are recovered through environmental cost recovery mechanisms when the remediation work is performed. See Note 3 under "Environmental Remediation" for additional information.

(g) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue. At December 31, 2022, the remaining amortization periods do not exceed 25 years for Alabama Power, 30 years for Georgia Power, 19 years for Mississippi Power, and five years for Southern Company Gas.

(h) Recorded as earned by employees and recovered as paid, generally within one year. Includes both vacation and banked holiday pay, if applicable.

(i) Effective January 1, 2023, balance is being amortized through Rate RSE over a five-year period ending in 2027.

(j) Represents certain deferred operations and maintenance costs associated with software and cloud computing projects. For Alabama Power, costs are amortized ratably over the life of the related software, which ranges up to 10 years. See "Alabama Power – Software Accounting Order" herein for additional information. For Georgia Power, costs incurred through 2022 will be amortized over five years starting in 2023 and the recovery period for all future costs will be determined in its next base rate case. For Southern Company Gas, costs began being amortized ratably in July 2022 over the life of the related software, which ranges up to 10 years.

(k) Nuclear outage costs are deferred to a regulatory asset when incurred and amortized over a subsequent period of 18 months for Alabama Power and up to 24 months for Georgia Power. See Note 5 for additional information.

(l) Recovered over the remaining lives of the original debt issuances at acquisition, which range up to 16 years at December 31, 2022.

(m) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts. Upon final settlement, actual costs incurred are recovered through the applicable traditional electric operating company's fuel cost recovery mechanism. Purchase contracts generally do not exceed three and a half years for Alabama Power, three years for Georgia Power, and four years for Mississippi Power.

(n) Mississippi Power's balance represents deferred storm costs associated with Hurricanes Ida and Zeta being recovered through PEP over an eight-year period through 2029.

(o) Represents the difference between Mississippi Power's revenue requirement for Plant Daniel Units 3 and 4 under purchase accounting and operating lease accounting. At December 31, 2022, consists of the $18 million retail portion being amortized through 2039 over the remaining life of the related property and the $9 million wholesale portion being amortized through 2035.

(p) Includes $26 million of regulatory assets and $6 million of regulatory liabilities at December 31, 2022. The retail portion includes $17 million of regulatory assets and $6 million of regulatory liabilities that are expected to be fully amortized by 2023 and 2025, respectively. The wholesale portion includes $10 million of regulatory assets that are expected to be fully amortized by 2035.

(q) Comprised of numerous immaterial components with remaining amortization periods generally not exceeding 21 years for Alabama Power, 10 years for Georgia Power, 14 years for Mississippi Power, and 20 years for Southern Company Gas at December 31, 2022.

(r) Utilized as related expenses are incurred. See "Alabama Power – Rate NDR" and " – Reliability Reserve Accounting Order," "Georgia Power – Storm Damage Recovery," and "Mississippi Power – System Restoration Rider" and " – Reliability Reserve Accounting Order" herein and Note 1 under "Storm Damage and Reliability Reserves" for additional information.

(s) Primarily includes approximately $62 million and $181 million at December 31, 2022 and 2021, respectively, for Alabama Power and $119 million and $5 million at December 31, 2022 and 2021, respectively, for Georgia Power as a result of each company exceeding its allowed retail return range. Georgia Power's balances also include immaterial amounts related to refunds for transmission service customers. See "Alabama Power – Rate RSE" and "Georgia Power – Rate Plans" herein for additional information.

(t) Comprised of numerous immaterial components with remaining amortization periods generally not exceeding 11 years for Alabama Power, 10 years for Georgia Power, four years for Mississippi Power, and 20 years for Southern Company Gas at December 31, 2022.

(u) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

Alabama Power

Alabama Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business primarily through Rate RSE,

Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting

Alabama Power.

Certificates of Convenience and Necessity

In 2020, the Alabama PSC issued its order regarding Alabama Power's 2019 petition for a CCN, which authorized Alabama Power to (i) construct an approximately 720-MW combined cycle facility at Alabama Power's Plant Barry (Plant Barry Unit 8) that is expected to be placed in service in November 2023, (ii) complete the acquisition of the Central Alabama Generating Station, which occurred in August 2020, (iii) purchase approximately 240 MWs of combined cycle generation under a long-term PPA, which began in September 2020, and (iv) pursue up to approximately 200 MWs of cost-effective demand-side management and distributed energy resource programs. Alabama Power's petition for a CCN was predicated on the results of Alabama Power's 2019 IRP provided to the Alabama PSC, which identified an approximately 2,400-MW resource need for Alabama Power, driven by the need for additional winter reserve capacity. See Note 15 under "Alabama Power" for additional information on the acquisition of the Central Alabama Generating Station.

The Alabama PSC authorized the recovery of actual costs for the construction of Plant Barry Unit 8 up to 5% above the estimated in-service cost of $652 million. In so doing, it recognized the potential for developments that could cause the project costs to exceed the capped amount, in which case Alabama Power would provide documentation to the Alabama PSC to explain and justify potential recovery of the additional costs. At December 31, 2022, project expenditures associated with Plant Barry Unit 8 totaled approximately $518 million, of which $513 million and $5 million was included in CWIP and property, plant, and equipment in service, respectively. The ultimate outcome of this matter cannot be determined at this time.

Alabama Power expects to recover costs associated with Plant Barry Unit 8 pursuant to its Rate CNP New Plant. The recovery of costs associated with laws, regulations, and other such mandates directed at the utility industry are expected to be recovered through Rate CNP Compliance. Alabama Power expects to recover the capacity-related costs associated with the PPAs through its Rate CNP PPA. In addition, fuel and energy-related costs are expected to be recovered through Rate ECR. Any remaining costs associated with Plant Barry Unit 8 are expected to be recovered through Rate RSE.

Through May 2023, Alabama Power expects to recover substantially all costs associated with the Central Alabama Generating Station through Rate RSE, offset by revenues from a previous power sales agreement. Beginning in July 2022, fuel costs associated with Central Alabama Generating Station are being recovered through Rate ECR.

On July 12, 2022, the Alabama PSC approved a CCN authorizing Alabama Power to complete the acquisition of the Calhoun Generating Station, a 743-MW winter peak, simple-cycle, combustion turbine generation facility in Calhoun County, Alabama. The acquisition was approved by the FERC on March 25, 2022. The transaction closed on September 30, 2022 and, on October 3, 2022, Alabama Power filed Rate CNP New Plant with the Alabama PSC to recover the related costs, as described further under "Rate CNP New Plant" herein. Alabama Power is recovering the remaining costs associated with the Calhoun Generating Station through its existing rate structure, primarily Rate CNP Compliance, Rate ECR, and Rate RSE.

Renewable Generation Certificate

Alabama Power is authorized by the Alabama PSC to procure up to 500 MWs of renewable capacity and energy by September 16, 2027 and to market the related energy and environmental attributes to customers and other third parties. Through December 31, 2022, Alabama Power has procured solar capacity totaling approximately 330 MWs.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted common equity return (WCER) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. When the projected WCER is under the allowed range, there is an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCER adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Alabama Power continues to reduce growth in total debt by increasing equity, with corresponding reductions in debt issuances, thereby de-leveraging its capital structure. Alabama Power's goal is to achieve an equity ratio of approximately 55% by the end of 2025. At December 31, 2022 and 2021, Alabama Power's equity ratio was approximately 52.2% and 51.6%, respectively.

Generally, during a year without a Rate RSE upward adjustment, if Alabama Power's actual WCER is between 6.15% and 7.65%, customers will receive 25% of the amount between 6.15% and 6.65%, 40% of the amount between 6.65% and 7.15%, and 75% of the amount between 7.15% and 7.65%. Customers will receive all amounts in excess of an actual WCER of 7.65%. During a year with a Rate RSE upward adjustment, if Alabama Power's actual WCER exceeds 6.15%, customers receive 50% of the amount between 6.15% and 6.90% and all amounts in excess of an actual WCER of 6.90%. Alabama Power's ability to retain a portion of the revenue that causes the actual WCER for a given year to exceed the allowed range positions Alabama Power to address the growing pressure on its credit quality, without increasing retail rates under Rate RSE in the near term. There is no provision for additional customer billings should the actual retail return fall below the WCER range.

Retail rates under Rate RSE did not change for 2020 or 2022 and increased by 4.09%, or approximately $228 million annually, effective with the billing month of January 2021.

At December 31, 2020, 2021, and 2022 Alabama Power's WCER exceeded 6.15%, resulting in Alabama Power establishing a current regulatory liability of $50 million, $181 million, and $62 million, respectively, for Rate RSE refunds. The 2020 refund was issued to customers through bill credits in April 2021. In accordance with an Alabama PSC order issued on February 1, 2022, Alabama Power applied $126 million of the 2021 refund to reduce the Rate ECR under recovered balance and the remaining $55 million was refunded to customers through bill credits in July 2022. See "Rate ECR" herein for additional information. On February 7, 2023, the Alabama PSC directed Alabama Power to issue the 2022 refund to customers through bill credits in August 2023.

On December 1, 2022, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2023. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remain unchanged for 2023.

Excess Accumulated Deferred Income Tax Accounting Order

On December 6, 2022, the Alabama PSC directed Alabama Power to accelerate the amortization of a regulatory liability associated with excess federal accumulated deferred income taxes, which is being returned to customers through bill credits of up to approximately $318 million in 2023 to offset the impact of the rate increase discussed under "Rate CNP Depreciation" herein. The Alabama PSC will determine the treatment of any remaining excess federal accumulated deferred income taxes at a future date. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP New Plant

Rate CNP New Plant allows for recovery of Alabama Power's retail costs associated with newly developed or acquired certificated generating facilities placed into retail service. No adjustments to Rate CNP New Plant occurred during the period January 2020 through October 2022. On October 3, 2022, Alabama Power filed Rate CNP New Plant with the Alabama PSC to recover costs related to the acquisition of the Calhoun Generating Station. The filing reflected an increase in annual revenues of $34 million, or 0.6%, effective with November 2022 billings. See "Certificates of Convenience and Necessity" herein for additional information.

Rate CNP PPA

Rate CNP PPA allows for the recovery of Alabama Power's retail costs associated with certificated PPAs. Revenues for Rate CNP PPA, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on Southern Company's or Alabama Power's revenues or net income but will affect annual cash flow. No adjustments to Rate CNP PPA occurred during the period 2020 through 2022 and no adjustment is expected for 2023. At December 31, 2022, Alabama Power had an under recovered Rate CNP PPA balance of $120 million, of which $18 million is included in other regulatory assets, current and $102 million is

included in other regulatory assets, deferred on the balance sheet. At December 31, 2021, Alabama Power had an under recovered Rate CNP PPA balance of $84 million included in other regulatory assets, deferred on the balance sheet.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of Alabama Power's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to factors that are calculated and submitted to the Alabama PSC by December 1 with rates effective for the following calendar year. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on Southern Company's or Alabama Power's revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In November 2020, November 2021, and December 2022, Alabama Power submitted calculations associated with its cost of complying with governmental mandates for the following calendar year, as provided under Rate CNP Compliance. Both the 2020 and 2021 filings reflected a projected under recovered retail revenue requirement of approximately $59 million. In December 2020 and 2021, the Alabama PSC issued consent orders that Alabama Power leave the 2020 Rate CNP Compliance factors in effect for 2021 and 2022, respectively, with any prior year under collected amount deemed recovered before any current year amounts are recovered, and any remaining under recovery reflected in the 2022 filing. The 2022 filing reflected a $255 million, or 3.7%, annual increase effective with January 2023 billings, primarily due to updated depreciation rates.

At December 31, 2022 and 2021, Alabama Power had an under recovered Rate CNP Compliance balance of $47 million and $16 million, respectively, included in other regulatory assets, current and other regulatory assets, deferred, respectively, on the balance sheet.

Rate CNP Depreciation

On December 6, 2022, the Alabama PSC approved Rate CNP Depreciation, which allows Alabama Power to recover changes in depreciation resulting from updates to certain depreciation rates, excluding any depreciation recovered through Rate CNP New Plant, Rate CNP Compliance, or costs associated with the capitalization of asset retirement costs. Rate CNP Depreciation will result in an annual revenue increase of approximately $318 million, or 4.6%, effective with January 2023 billings. See "Excess Accumulated Deferred Income Tax Accounting Order" herein for information related to 2023 customer bill credits approved by the Alabama PSC.

Rate ECR

Rate ECR recovers Alabama Power's retail energy costs based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed gives rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on Southern Company's or Alabama Power's net income but will impact the related operating cash flows. The Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

In 2020, Alabama Power reduced its over-collected fuel balance by $94 million in accordance with an Alabama PSC order and returned that amount to customers in the form of bill credits.

Also in 2020, the Alabama PSC approved a decrease to Rate ECR from 2.160 cents per KWH to 1.960 cents per KWH, equal to 1.84%, or approximately $103 million annually, that became effective with January 2021 billings and remained in effect through July 2022 billings.

The Alabama PSC approved adjustments to Rate ECR from 1.960 cents per KWH to 2.557 cents per KWH, or approximately $310 million annually, effective with August 2022 billings and from 2.557 cents per KWH to 3.510 cents per KWH, or approximately $500 million annually, effective with December 2022 billings. The rate will adjust to 5.910 cents per KWH in January 2025 absent a further order from the Alabama PSC.

In accordance with an Alabama PSC order issued on February 1, 2022, Alabama Power applied $126 million of its 2021 Rate RSE refund to reduce the Rate ECR under recovered balance. See "Rate RSE" herein for additional information. At December 31, 2022, Alabama Power's under recovered fuel costs totaled $622 million, of which $102 million is included in other regulatory assets, current and $520 million is included in other regulatory assets, deferred on the balance sheet. At December 31, 2021, Alabama Power's under recovered fuel costs totaled $126 million and is included in other regulatory assets, deferred on the balance sheet. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a significant impact on the timing of any recovery or return of fuel costs.

Software Accounting Order

The Alabama PSC authorizes Alabama Power to establish a regulatory asset for operations and maintenance costs associated with software implementation projects. The regulatory asset is amortized ratably over the life of the related software. At December 31, 2022 and 2021, the regulatory asset balance totaled $46 million and $35 million, respectively, and is included in other regulatory assets, deferred on the balance sheet.

Plant Greene County

Alabama Power jointly owns Plant Greene County with an affiliate, Mississippi Power. See Note 5 under "Joint Ownership Agreements" for additional information. In September 2021, the Mississippi PSC issued an order confirming the conclusion of its review of Mississippi Power's 2021 IRP with no deficiencies identified. Mississippi Power's 2021 IRP included a schedule to retire Mississippi Power's 40% ownership interest in Plant Greene County Units 1 and 2 in December 2025 and 2026, respectively, consistent with each unit's remaining useful life. The Plant Greene County unit retirements identified by Mississippi Power require the completion of transmission and system reliability improvements, as well as agreement by Alabama Power. Alabama Power will continue to monitor the status of the transmission and system reliability improvements. Currently, Alabama Power plans to retire Plant Greene County Units 1 and 2 at the dates indicated. The ultimate outcome of this matter cannot be determined at this time.

Rate NDR

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. When the reserve balance falls below $50 million, a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million.

The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 48-month period (24-month period prior to modifications approved by the Alabama PSC on July 12, 2022). The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. The maximum total Rate NDR charge was limited to $10.00 per month per non-residential customer account and $5.00 per month per residential customer account through July 12, 2022. Subsequently, modifications approved by the Alabama PSC replaced the maximum total Rate NDR charge with a maximum charge to recover a deficit of $5 per month per non-residential customer account and $2.50 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant, which can be used to offset storm charges. Alabama Power made additional accruals of $65 million and $100 million in 2021 and 2020, respectively.

Alabama Power collected approximately $14 million, $6 million, and $5 million in 2022, 2021, and 2020, respectively, under Rate NDR. Beginning with August 2022 billings, the reserve establishment charge was suspended and the reserve maintenance charge was activated as a result of the NDR balance exceeding $75 million. Alabama Power expects to collect approximately $12 million annually under Rate NDR unless the NDR balance falls below $50 million. At December 31, 2022 and 2021, the NDR balance was $97 million and $103 million, respectively, and is included in other regulatory liabilities, deferred on the balance sheets.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Reliability Reserve Accounting Order

On July 12, 2022, the Alabama PSC approved an accounting order authorizing Alabama Power to create a reliability reserve separate from the NDR and transition the previous Rate NDR authority related to reliability expenditures to the reliability reserve. Alabama Power may make accruals to the reliability reserve if the NDR balance exceeds $35 million. At December 31, 2022, Alabama Power accrued $166 million to the reserve, which is included in other regulatory liabilities, deferred on the balance sheet.

Environmental Accounting Order

Based on an order from the Alabama PSC (Environmental Accounting Order), Alabama Power is authorized to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. The regulatory asset is amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement, through Rate CNP Compliance.

With the completion of the Calhoun Generating Station acquisition, Alabama Power expects to retire Plant Barry Unit 5 in late 2023 or early 2024, subject to certain operating conditions. In September 2022, Alabama Power reclassified approximately $600 million for Plant Barry Unit 5 from plant in service, net of depreciation to other utility plant, net and will continue to depreciate the asset according to the original depreciation rates. At retirement, Alabama Power will reclassify the remaining net investment costs of the unit to a regulatory asset to be recovered over the unit's remaining useful life, as established prior to the decision to retire, through Rate CNP Compliance. See "Certificates of Convenience and Necessity" herein for additional information.

On December 5, 2022, in conjunction with Alabama Power's compliance plan for the EPA's final steam electric ELG reconsideration rule, Plant Barry Unit 4 ceased using coal and began operating solely on natural gas. As a result, approximately $42 million of plant in service, net of depreciation was reclassified to a regulatory asset to be recovered through Rate CNP Compliance through 2034, the unit's remaining useful life.

Georgia Power

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power recovers its costs from the

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power recovers its costs from the regulated retail business through traditional base tariffs, Demand-Side Management (DSM) tariffs, the ECCR tariff, and Municipal Franchise Fee (MFF) tariffs. These tariffs were set under the 2019 ARP for the years 2020 through 2022 and under the 2022 ARP for the years 2023 through 2025 as described herein. In addition, financing costs on certified construction costs of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through a fuel cost recovery tariff, both under separate regulatory proceedings.

See "Plant Vogtle Unit 3 and Common Facilities Rate Proceeding" herein for information regarding the approved recovery through retail base rates of certain costs related to Plant Vogtle Unit 3 and the common facilities shared between Plant Vogtle Units 3 and 4 (Common Facilities) that will become effective the month after Unit 3 is placed in service. As costs are included in retail base rates, the related financing costs will no longer be recovered through the NCCR tariff. See "Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.

Rate Plans

2022 ARP

On December 20, 2022, the Georgia PSC voted to approve the 2022 ARP, under which Georgia Power increased its rates on January 1, 2023 and will increase rates annually for 2024 and 2025 as detailed below, with the incremental revenue requirements related to DSM tariffs and CCR AROs subject to updates through annual compliance filings to be made at least 90 days prior to the effective date. Georgia Power will recover estimated adjustments through its existing tariffs as follows:

Tariff	2023	2024	2025
		(in millions)	
Traditional base	$ 194	$ 275	$ 315
ECCR	(21)	66	81
DSM	37	27	(2)
MFF	6	9	9
Total	$ 216	$ 377	$ 403

In the 2022 ARP, the Georgia PSC approved recovery through the ECCR tariff of estimated CCR ARO compliance costs for 2023, 2024, and 2025 over four-year periods beginning January 1 of each respective year, with recovery of construction contingency beginning in the year following actual expenditures, resulting in an estimated $20 million reduction in the related amortization expense for 2023. The estimated compliance costs expected to be incurred in 2023, 2024, and 2025 are $320 million, $410 million, and $510 million, respectively. The CCR ARO costs are expected to be revised for actual expenditures and updated estimates through future annual compliance filings. See "Integrated Resource Plans" herein for additional information.

Further, under the 2022 ARP, Georgia Power's retail ROE is set at 10.50% and its equity ratio is set at 56%. Earnings will be evaluated against a retail ROE range of 9.50% to 11.90%. Any retail earnings above 11.90% will be shared, with 40% being applied to reduce regulatory assets, 40% directly refunded to customers, and the remaining 20% retained by Georgia Power. There will be no recovery of any earnings shortfall below 9.50% on an actual basis. However, if at any time during the term of the 2022 ARP, Georgia Power projects that its retail earnings will be below 9.50% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff to adjust Georgia Power's retail rates to achieve a 9.50% ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff would expire at the earlier of January 1, 2026 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2022 ARP is in effect. Georgia Power is required to file a general base rate case by July 1, 2025, in response to which the Georgia PSC would be expected to determine whether the 2022 ARP should be continued, modified, or discontinued.

2019 ARP

The Georgia PSC approved the following tariff adjustments under the 2019 ARP effective January 1, 2021 and 2022, respectively:

Tariff	2021	2022
	(in millions)	
Traditional base	$ 120	$ 192
ECCR	2	(12)
DSM	(15)	(25)
MFF	4	2
Total	$ 111	$ 157

In the 2019 ARP, the Georgia PSC approved recovery through the ECCR tariff of the estimated under recovered balance of CCR ARO compliance costs. Under the 2019 ARP, the under recovered balance at December 31, 2019 and compliance costs for 2020 were recovered over the three-year period ended December 31, 2022. Recovery of estimated compliance costs for 2021 and 2022 are being recovered over four-year periods beginning January 1 of each respective year, as authorized under the 2019 ARP and modified under the 2022 ARP, with recovery of construction contingency beginning in the year following actual expenditure. The CCR ARO costs recovered through the ECCR tariff are revised for actual expenditures and updated estimates through annual compliance filings, which resulted in an approximate $90 million decrease and $10 million increase effective January 1, 2021 and 2022, respectively, in the related cost recovery. See "Integrated Resource Plans" herein for additional information.

Georgia Power's retail ROE under the 2019 ARP was set at 10.50% and earnings were evaluated against a retail ROE range of 9.50% to 12.00%. Any retail earnings above 12.00% were shared, with 40% applied to reduce regulatory assets, 40% directly refunded to customers, and the remaining 20% retained by Georgia Power. In 2020, Georgia Power's retail ROE was within the allowed retail ROE range. In 2021, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power reduced regulatory assets by approximately $5 million and accrued approximately $5 million which was refunded to customers in 2022. In 2022, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power reduced regulatory assets by approximately $119 million and accrued approximately $119 million, which is expected to be refunded to customers through bill credits later in the first quarter 2023, prior to review and approval by the Georgia PSC, in accordance with the 2022 ARP.

Plant Vogtle Unit 3 and Common Facilities Rate Proceeding

In accordance with a Georgia PSC order approved in November 2021, Georgia Power will include in rate base an allocation of $2.1 billion to Unit 3 and Common Facilities from the $3.6 billion of Plant Vogtle Units 3 and 4 previously deemed prudent by the Georgia PSC and will recover the related depreciation expense through retail base rates effective the month after Unit 3 is placed in service. Financing costs on the remaining portion of the total Unit 3 and the Common Facilities construction costs will continue to be recovered through the NCCR tariff or deferred. Georgia Power will defer as a regulatory asset the remaining depreciation expense (approximately $40 million annually) until Unit 4 costs are placed in retail base rates. In addition, the stipulated agreement clarified that following the prudency review, the remaining amount to be placed in retail base rates will be net of the proceeds from the Guarantee Settlement Agreement and will not be used to offset imprudent costs, if any.

The related increase in annual retail base rates of approximately $302 million also includes recovery of all projected operations and maintenance expenses for Unit 3 and the Common Facilities and other related costs of operation, partially offset by the related production tax credits, and will become effective the month after Unit 3 is placed in service. As approved by the Georgia PSC, the increase in annual retail base rates will be adjusted based on the actual in-service date of Plant Vogtle Unit 3.

See "Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.

Integrated Resource Plans

In 2021, as authorized in its 2019 IRP, Georgia Power requested and received certification from the Georgia PSC for 970 MWs of utility-scale PPAs for solar generation resources. In response to supply chain challenges in the solar industry, the Georgia PSC approved a request by Georgia Power to extend the required commercial operation dates for the PPAs from 2023 to 2024.

On July 21, 2022, the Georgia PSC approved Georgia Power's triennial IRP (2022 IRP), as modified by a stipulated agreement among Georgia Power, the staff of the Georgia PSC, and certain intervenors and as further modified by the Georgia PSC. In the 2022 IRP decision, the Georgia PSC approved the following:

- Decertification and retirement of Plant Wansley Units 1 and 2 (926 MWs based on 53.5% ownership), which occurred on August 31, 2022, and reclassification to regulatory asset accounts of the remaining net book values and any remaining unusable materials and supplies inventories upon retirement. The regulatory asset accounts for the remaining net book values of the units ($292 million and $270 million for Unit 1 and Unit 2, respectively, at December 31, 2022) were amortized at a rate equal to the unit depreciation rates authorized in the 2019 ARP through

December 31, 2022. Under the 2022 ARP, the Georgia PSC approved recovery of the remaining regulatory asset balances for the net book values of

the units through 2030 and deferred a decision on the timing of recovery of the regulatory asset account for the unusable materials and supplies inventories ($13 million at December 31, 2022) to a future base rate case.

- Decertification and retirement of Plant Scherer Unit 3 (614 MWs based on 75% ownership) by December 31, 2028 and reclassification to regulatory asset accounts of the remaining net book value (approximately $601 million at December 31, 2022). Under the 2022 ARP, $43 million annually of the related depreciation is being deferred to a regulatory asset, which will be amortized over six years beginning in 2029. Any remaining unusable materials and supplies inventory will be reclassified to regulatory asset accounts upon retirement, with the timing of recovery to be determined in a future base rate case.
- Decertification and retirement of Plant Gaston Units 1 through 4 (500 MWs based on 50% ownership through SEGCO) by December 31, 2028. See Note 7 under "SEGCO" for additional information.
- Georgia Power's environmental compliance strategy, including approval of Georgia Power's plans to address CCR at its ash ponds and landfills. Recovery of the related costs incurred beyond 2025 is expected to be determined in future base rate cases. The Georgia PSC's approval of the 2022 IRP included a change in the method of closure for one ash pond. See "Rate Plans" herein and Note 6 for additional information.
- Installation of environmental controls at Plants Bowen and Scherer for compliance with rules related to effluent limitations guidelines.
- Initiation of a license renewal application with the NRC for Plant Hatch.
- Investments related to the continued hydro operations of Plants Sinclair and Burton.
- Provisional authorization for development of a 265-MW battery energy storage facility with expected commercial operation in 2026.
- Issuance of requests for proposals (RFP) for 2,300 MWs of renewable resources, an additional 500 MWs of energy storage, and up to 140 MWs of biomass generation.
- Related transmission projects necessary to support the generation facilities plan.
- Certification of six PPAs (including five affiliate PPAs with Southern Power that are subject to approval by the FERC) with capacities of 1,567 MWs beginning in 2024, 380 MWs beginning in 2025, and 228 MWs beginning in 2028, procured through RFPs authorized in the 2019 IRP. See Note 9 for additional information.

The Georgia PSC deferred a decision on the requested decertification and retirement of Plant Bowen Units 1 and 2 (1,400 MWs) to the 2025 IRP. Under the 2022 ARP, $40 million annually of the related depreciation is being deferred to a regulatory asset, which will be amortized over four years beginning in 2031. The Georgia PSC rejected Georgia Power's request to certify approximately 88 MWs of wholesale capacity to be placed in retail rate base between January 1, 2024 and January 1, 2025. Georgia Power may offer such capacity in the wholesale market or to the retail jurisdiction in a future regulatory proceeding.

On August 26, 2022, Restore Chattooga Gorge Coalition (RCG) filed a petition in the Superior Court of Fulton County, Georgia against Georgia Power and the Georgia PSC. The petition challenges Georgia Power's plan to expend $115 million to modernize Plant Tugalo, as approved in the 2019 IRP, and seeks judicial review of the Georgia PSC's order in the 2022 IRP proceeding with respect to the denial of RCG's challenge to the modernization plan. On November 7, 2022, Georgia Power and the Georgia PSC both filed motions to dismiss the RCG petition.

The ultimate outcome of these matters cannot be determined at this time.

Deferral of Incremental COVID-19 Costs

During 2020, in response to the COVID-19 pandemic, the Georgia PSC approved orders directing Georgia Power to defer as a regulatory asset the incremental bad debt resulting from the approved suspension of customer disconnections during certain periods in 2020. The Georgia PSC approved orders establishing a methodology for identifying incremental bad debt and allowing the deferral of other incremental costs associated with the COVID-19 pandemic. At December 31, 2022 and 2021, the incremental costs deferred totaled approximately $25 million and $21 million, respectively. In the 2022 ARP, the Georgia PSC approved a three-year recovery period ending December 31, 2025.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. In 2020, the Georgia PSC approved a stipulation agreement among Georgia Power, the staff of the Georgia PSC, and certain intervenors to lower total fuel billings by approximately $740 million over a two-year period effective June 1, 2020. In addition, Georgia Power further lowered fuel billings by approximately $44 million under an interim fuel rider effective June 1, 2020 through September 30, 2020. During the second half of 2021, the price of natural gas rose significantly and resulted in an under recovered fuel balance exceeding $200 million. Therefore, in November 2021, the Georgia PSC voted to approve Georgia Power's interim fuel rider, which increased fuel rates by 15%, or approximately $252 million annually, effective January 1, 2022. During 2022, Georgia Power's under recovered fuel balance continued to increase significantly due to higher fuel and purchased power costs. Georgia Power is scheduled to file its next fuel case no later than February 28, 2023.

Georgia Power's under recovered fuel balance totaled $2.1 billion and $0.4 billion at December 31, 2022 and 2021, respectively, and is included in deferred under recovered fuel clause revenues on Southern Company's and Georgia Power's balance sheets.

Georgia Power's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 36-month time horizon.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's or Georgia Power's revenues or net income but will affect operating cash flows.

See Note 17 under "Georgia Power – Fuel Cost Recovery" for additional information.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. During 2020 through 2022, Georgia Power recovered $213 million annually under the 2019 ARP. Effective January 1, 2023, Georgia Power is recovering $31 million annually under the 2022 ARP. At December 31, 2022, Georgia Power's storm damage reserve balance was $83 million and is included in other regulatory liabilities, deferred on Southern Company's balance sheets and other deferred credits and liabilities on Georgia Power's balance sheets. At December 31, 2021, Georgia Power's regulatory asset balance related to storm damage was $48 million and is included in other regulatory assets, current on Southern Company's and Georgia Power's balance sheets. The rate of storm damage cost recovery is expected to be adjusted in future regulatory proceedings as necessary. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's or Georgia Power's financial statements. See Note 1 under "Storm Damage and Reliability Reserves" for additional information.

Nuclear Construction

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4, in which Georgia Power currently holds a 45.7% ownership interest. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement.

In connection with the EPC Contractor's bankruptcy filing in March 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, entered into several transitional arrangements to allow construction to continue. In July 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, entered into the Vogtle Services Agreement, whereby Westinghouse provides facility design and engineering services, procurement and technical support, and staff augmentation on a time and materials cost basis. The Vogtle Services Agreement provides that it will continue until the start-up and testing of Plant Vogtle Units 3 and 4 are complete and electricity is generated and sold from both units. The Vogtle Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

In October 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, executed the Bechtel Agreement, under which Bechtel is reimbursed for actual costs plus a base fee and an at-risk fee, subject to adjustment based on Bechtel's

performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Vogtle Owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs, and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Vogtle Owner suspensions of work, certain breaches of the Bechtel Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

See Note 8 under "Long-term Debt – DOE Loan Guarantee Borrowings" for information on the Amended and Restated Loan Guarantee Agreement, including applicable covenants, events of default,

and mandatory prepayment events.

Cost and Schedule

Georgia Power's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4, including contingency, through the end of the second quarter 2023 and the first quarter 2024, respectively, is as follows:

	(in millions)
Base project capital cost forecast[(a)(b)]	$ 10,533
Construction contingency estimate	60
Total project capital cost forecast[(a)(b)]	10,593
Net investment at December 31, 2022[(b)]	(9,521)
Remaining estimate to complete	**$ 1,072**

(a) Includes approximately $610 million of costs that are not shared with the other Vogtle Owners, including $33 million of construction monitoring costs approved for recovery by the Georgia PSC in its nineteenth VCM order, and approximately $407 million of incremental costs under the cost-sharing and tender provisions of the joint ownership agreements described below. Excludes financing costs expected to be capitalized through AFUDC of approximately $421 million, of which $304 million had been accrued through December 31, 2022.

(b) Net of $1.7 billion received from Toshiba under the Guarantee Settlement Agreement and approximately $188 million in related customer refunds.

Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.5 billion, of which $3.2 billion had been incurred through December 31, 2022.

As part of its ongoing processes, Southern Nuclear continues to evaluate cost and schedule forecasts on a regular basis to incorporate current information available, particularly in the areas of start-up testing and related test results, engineering support, commodity installation, system turnovers, and workforce statistics. Southern Nuclear establishes aggressive target values for monthly construction production and system turnover activities, which are reflected in the site work plans.

Since March 2020, the number of active COVID-19 cases at the site has fluctuated consistent with the surrounding area and impacted productivity levels and pace of activity completion, with the site experiencing peaks in the number of active cases in January 2021, August 2021, and January 2022. Georgia Power estimates the productivity impacts of the COVID-19 pandemic have consumed approximately three to four months of schedule margin previously embedded in the site work plans. As of December 31, 2022, Georgia Power's proportionate share of the estimated incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity is estimated to be between $160 million and $200 million and is included in the total project capital cost forecast. Future COVID-19 variants could further disrupt or delay construction and testing activities.

On July 29, 2022, Southern Nuclear announced that all Unit 3 ITAACs had been submitted to the NRC. On August 3, 2022, the NRC published its 103(g) finding that the acceptance criteria in the combined license for Unit 3 had been met, which allowed nuclear fuel to be loaded and start-up testing to begin. Fuel load for Unit 3 was completed on October 17, 2022. In early 2023, during the start-up and pre-operational testing for Unit 3, Southern Nuclear identified and is remediating certain equipment and component issues. As a result, Unit 3 is projected to be placed in service during May or June 2023. After considering the timeframe and duration of hot functional and other testing and recent experience with Unit 3 start-up and pre-operational testing, Unit 4 is now projected to be placed in service during late fourth quarter 2023 or the first quarter 2024.

During 2022, established construction contingency and additional costs totaling $307 million were assigned to the base capital cost forecast for costs primarily associated with schedule extensions, construction productivity, the pace of system turnovers, additional craft and support resources, procurement for Units 3 and 4, and the equipment and component issues identified during Unit 3 start-up and pre-operational testing. During 2022, Georgia Power also increased its total project capital cost forecast by $125 million to replenish construction contingency and $9 million for construction monitoring costs, which were approved for recovery by the Georgia PSC in its nineteenth VCM order.

After considering the significant level of uncertainty that exists regarding the future recoverability of these costs since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in future regulatory proceedings, Georgia Power recorded pre-tax charges to income in the second quarter 2022, the third quarter 2022, and the fourth quarter 2022 of $36 million ($27 million after tax), $32 million ($24 million after tax), and $148 million ($110 million after tax), respectively, for the increases in the total project capital cost forecast. Georgia Power may request the Georgia PSC to evaluate those expenditures for rate recovery during the prudence review following the Unit 4 fuel load pursuant to the twenty-fourth VCM stipulation described below.

The projected schedule for Unit 3 primarily depends on the progression of final component and pre-operational testing and start-up, which may be impacted by further equipment, component, and/or other operational challenges. The projected schedule for Unit 4 primarily depends on potential impacts arising from Unit 4 testing activities overlapping with Unit 3 start-up and commissioning; maintaining overall construction productivity and production levels, particularly in subcontractor scopes of work; and maintaining appropriate levels of craft laborers. As Unit 4 completes construction and transitions further into testing, ongoing and potential future challenges include the timeframe and duration of hot functional and other testing; the pace and quality of remaining commodities installation; completion of documentation to support ITAAC submittals; the pace of remaining work package closures and system turnovers; and the availability of craft, supervisory, and technical support resources. Ongoing or future challenges for both units also include management of contractors and vendors; subcontractor performance; and/or related cost escalation. New challenges also may continue to arise, as Unit 3 completes start-up and commissioning and Unit 4 moves further into testing and start-up, which may result in required engineering changes or remediation related to plant systems, structures, or components (some of which are based on new technology that only within the last few years began initial operation in the global nuclear industry at this scale). These challenges may result in further schedule delays and/or cost increases.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to ensure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. With the receipt of the NRC's 103(g) finding, Unit 3 is now subject to the NRC's operating reactor oversight process and must meet applicable technical and operational requirements contained in its operating license. Various design and other licensing-based compliance matters, including the timely submittal by Southern Nuclear of the ITAAC documentation and the related reviews and approvals by the NRC necessary to support NRC authorization to load fuel for Unit 4, may arise, which may result in additional license amendment requests or require other resolution. If any license amendment requests or other licensing-based compliance issues, including inspections and ITAACs for Unit 4, are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

The ultimate outcome of these matters cannot be determined at this time. However, any extension of the in-service date beyond the second quarter 2023 for Unit 3 or the first quarter 2024 for Unit 4, including the joint owner cost sharing and tender impacts described below, is estimated to result in additional base capital costs for Georgia Power of up to $15 million per month for Unit 3 and $35 million per month for Unit 4, as well as the related AFUDC and any additional related construction, support resources, or testing costs. While Georgia Power is not precluded from seeking retail recovery of any future capital cost forecast increase other than the amounts related to the cost-sharing and tender provisions of the joint ownership agreements described below, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Joint Owner Contracts

In November 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 to provide for, among other conditions, additional Vogtle Owner approval requirements. Effective in August 2018, the Vogtle Owners further amended the joint ownership agreements to clarify and provide procedures for certain provisions of the joint ownership agreements related to adverse events that require the vote of the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 to continue construction (as amended, and together with the November 2017 amendment, the Vogtle Joint Ownership Agreements). The Vogtle Joint Ownership Agreements also confirm that the Vogtle Owners' sole recourse against Georgia Power or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of Georgia Power and/or Southern Nuclear as agent, except in cases of willful misconduct.

Amendments to the Vogtle Joint Ownership Agreements

In connection with a September 2018 vote by the Vogtle Owners to continue construction, Georgia Power entered into (i) a binding term sheet (Vogtle Owner Term Sheet) with the other Vogtle Owners and MEAG Power's wholly-owned subsidiaries MEAG Power SPVJ, LLC (MEAG SPVJ), MEAG Power SPVM, LLC (MEAG SPVM), and MEAG Power SPVP, LLC (MEAG SPVP) to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners, including additional amendments to the Vogtle Joint Ownership Agreements and the purchase of PTCs from the other Vogtle Owners at pre-established prices, and (ii) a term sheet (MEAG Term Sheet) with MEAG Power and MEAG SPVJ to provide up to $300 million of funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 under certain circumstances. In January 2019, Georgia Power, MEAG Power, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet. In February 2019, Georgia Power, the other Vogtle Owners, and MEAG Power's wholly-owned subsidiaries MEAG SPVJ, MEAG SPVM, and MEAG SPVP

entered into certain amendments to the Vogtle Joint Ownership Agreements to implement the provisions of the Vogtle Owner Term Sheet (Global Amendments).

Pursuant to the Global Amendments: (i) each Vogtle Owner must pay its proportionate share of qualifying construction costs for Plant Vogtle Units 3 and 4 based on its ownership percentage up to the estimated cost at completion (EAC) for Plant Vogtle Units 3 and 4, of which Georgia Power's share is $8.4 billion (VCM 19 Forecast Amount), plus $800 million; (ii) Georgia Power will be responsible for 55.7% of actual qualifying construction costs between $800 million and $1.6 billion over the VCM 19 Forecast Amount (resulting in $80 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests; and (iii) Georgia Power will be responsible for 65.7% of qualifying construction costs between $1.6 billion and $2.1 billion over the VCM 19 Forecast Amount (resulting in a further $100 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests. The Global Amendments provide that if the EAC is revised and exceeds the VCM 19 Forecast Amount by more than $2.1 billion, each of the other Vogtle Owners will have a one-time option at the time the project budget cost forecast is so revised to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Vogtle Owner's remaining share of total construction costs in excess of the VCM 19 Forecast Amount plus $2.1 billion.

For purposes of the foregoing provisions, qualifying construction costs will not include costs (i) resulting from force majeure events, including epidemics and quarantines, governmental actions or inactions (or significant delays associated with issuance of such actions) that affect the licensing, completion, start-up, operations, or financing of Plant Vogtle Units 3 and 4, administrative proceedings or litigation regarding ITAAC or other regulatory challenges to commencement of operation of Plant Vogtle Units 3 and 4, and changes in laws or regulations governing Plant Vogtle Units 3 and 4, (ii) legal fees and legal expenses incurred due to litigation with contractors or subcontractors that are not subsidiaries or affiliates of Southern Company, and (iii) additional costs caused by requests from the Vogtle Owners other than Georgia Power, except for the exercise of a right to vote granted under the Vogtle Joint Ownership Agreements, that increase costs by $100,000 or more.

In addition, pursuant to the Global Amendments, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain adverse events (Project Adverse Events) occur, including, among other events: (i) the bankruptcy of Toshiba; (ii) the termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement, the Bechtel Agreement, or the agency agreement with Southern Nuclear; (iii) Georgia Power's public announcement

of its intention not to submit for rate recovery any portion of its investment in Plant Vogtle Units 3 and 4 or the Georgia PSC determines that any of Georgia Power's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Vogtle Owners pursuant to the Global Amendments described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia PSC for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates; and (iv) an incremental extension of one year or more from the seventeenth VCM report estimated in-service dates of November 2021 and November 2022 for Units 3 and 4, respectively. The schedule extension announced in February 2022 triggered the requirement for a vote to continue construction. Effective February 25, 2022, all of the Vogtle Owners had voted to continue construction.

Georgia Power and the other Vogtle Owners do not agree on either the starting dollar amount for the determination of cost increases subject to the cost-sharing and tender provisions of the Global Amendments or the extent to which COVID-19-related costs impact those provisions. The other Vogtle Owners notified Georgia Power that they believe the project capital cost forecast approved by the Vogtle Owners on February 14, 2022 triggered the tender provisions. On June 17, 2022 and July 26, 2022, OPC and Dalton, respectively, notified Georgia Power of their purported exercises of their tender options. Georgia Power did not accept these purported tender exercises.

On June 18, 2022, OPC and MEAG Power each filed a separate lawsuit against Georgia Power in the Superior Court of Fulton County, Georgia seeking a declaratory judgment that the starting dollar amount is $17.1 billion and that the cost-sharing and tender provisions have been triggered. The lawsuits also assert other claims, including breach of contract allegations, and seek, among other remedies, damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with MEAG Power's and OPC's interpretations of the Global Amendments. On July 25, 2022 and July 28, 2022, Georgia Power filed its answers in the lawsuits filed by MEAG Power and OPC, respectively, and included counterclaims seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power's related financial obligations. On September 26, 2022, Dalton filed complaints in each of these lawsuits. On September 29, 2022, Georgia Power and MEAG Power reached an agreement to resolve their dispute regarding the proper interpretation of the cost-sharing and tender provisions of the Global Amendments. Under the terms of the agreement, among other items, (i) MEAG Power will not exercise its tender option and will retain its full ownership interest in Plant Vogtle Units 3 and 4; (ii) Georgia Power will reimburse a portion of MEAG Power's costs of construction for Plant Vogtle Units 3 and 4 as such costs are incurred and with no further adjustment for force majeure costs, which payments will total approximately $92 million based on the current project capital cost forecast; and (iii) Georgia Power will reimburse 20% of MEAG Power's costs of construction with respect to any amounts over the current project capital cost forecast, with no further adjustment for force majeure costs. In addition, MEAG Power agreed to vote to continue construction upon occurrence of a Project Adverse Event unless the commercial operation date of either of Plant Vogtle Unit 3 or Unit 4 is not projected to occur by December 31, 2025. On October 4, 2022, MEAG Power and Georgia Power filed a notice of settlement and voluntary dismissal of their pending litigation, including Georgia Power's counterclaim, and, on October 6, 2022, Dalton dismissed its related complaint.

Georgia Power recorded pre-tax charges (credits) to income in the fourth quarter 2021, the second quarter 2022, the third quarter 2022, and the fourth quarter 2022 of approximately $440 million ($328 million after tax), $16 million ($12 million after tax), $(102) million ($(76) million after tax), and $53 million ($40 million after tax), respectively, associated with the cost-sharing and tender provisions of the Global Amendments, including the settlement with MEAG Power. A total of $407 million associated with these provisions is included in the total project capital cost forecast and will not be recovered from retail customers. The settlement with MEAG Power does not resolve the separate pending litigation with OPC, including Dalton's associated complaint, described above. Georgia Power may be required to record further pre-tax charges to income of up to approximately $345 million associated with the cost-sharing and tender provisions of the Global Amendments for OPC and Dalton based on the current project capital cost forecast.

Georgia Power's ownership interest in Plant Vogtle Units 3 and 4 continues to be 45.7%. Georgia Power believes the increases in the total project capital cost forecast through December 31, 2022 will trigger the tender provisions, but Georgia Power disagrees with OPC and Dalton on the tender provisions trigger date. Valid notices of tender from OPC and Dalton would require Georgia Power to pay 100% of their respective remaining shares of the costs necessary to complete Plant Vogtle Units 3 and 4. Georgia

Power's incremental ownership interest will be calculated and conveyed to Georgia Power after Plant Vogtle Units 3 and 4 are placed in service.

The ultimate outcome of these matters cannot be determined at this time.

Regulatory Matters

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for Plant Vogtle Units 3 and 4. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion. At December 31, 2022, Georgia Power had recovered approximately $2.9 billion of financing costs. Financing costs related to capital costs above $4.418 billion are being recognized through AFUDC and are expected to be recovered through retail rates over the life of Plant Vogtle Units 3 and 4; however, Georgia Power is not recording AFUDC related to any capital costs in excess of the total deemed reasonable by the Georgia PSC (currently $7.3 billion) and not requested for rate recovery. On December 20, 2022, the Georgia PSC approved Georgia Power's filing to increase the NCCR tariff by $36 million annually, effective January 1, 2023.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 of each year. In 2013, in connection with the eighth VCM report, the Georgia PSC approved a stipulation between Georgia Power and the staff of the Georgia PSC to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate in accordance with the 2009 certification order until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

In 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudency matters in connection with the fifteenth VCM report. In December 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) Georgia Power's seventeenth VCM report and modified the Vogtle Cost Settlement Agreement. The Vogtle Cost Settlement Agreement, as modified by the January 11, 2018 order, resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the $0.3 billion paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.68 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) Georgia Power would have the burden to show that any capital costs above $5.68 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and related customer refunds) was found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable Georgia Power's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that a prudence proceeding on cost recovery will occur following Unit 4 fuel load, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC at that time) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30%, effective January 1, 2020, and (c) from 8.30% to 5.30%, effective January 1, 2021 (provided that the ROE in no case will be less than Georgia Power's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to Georgia Power's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that effective the first month after Unit 3

reaches commercial operation, retail base rates would be adjusted to include the costs related to Unit 3 and common facilities deemed prudent in the Vogtle Cost Settlement Agreement (see "Plant Vogtle Unit 3 and Common Facilities Rate Proceeding" herein for additional information). The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than Georgia Power's average cost of long-term debt) until the respective Unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $300 million, $270 million, and $150 million in 2022, 2021, and 2020, respectively, and are estimated to have negative earnings

impacts of approximately $270 million in 2023 and $60 million in 2024. In its January 11, 2018 order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

In the August 2021 order approving the twenty-fourth VCM report, the Georgia PSC approved a stipulation addressing the following matters: (i) beginning with its twenty-fifth VCM report, Georgia Power will continue to report to the Georgia PSC all costs incurred during the period for review and will request for approval costs up to the $7.3 billion determined to be reasonable in the Georgia PSC's seventeenth VCM order and (ii) Georgia Power will not seek rate recovery of the $0.7 billion increase to the base capital cost forecast included in the nineteenth VCM report and charged to income by Georgia Power in the second quarter 2018. In addition, the stipulation confirms Georgia Power may request verification and approval of costs above $7.3 billion for inclusion in rate base at a later time, but no earlier than the prudence review contemplated by the seventeenth VCM order described previously.

The Georgia PSC has approved 25 VCM reports covering periods through June 30, 2021. These reports reflect total construction capital costs incurred of $7.9 billion (net of $1.7 billion of payments received under the Guarantee Settlement Agreement and approximately $188 million in related customer refunds), of which the Georgia PSC has verified and approved $7.3 billion as described above. The Georgia PSC also has reviewed two additional VCM reports, which reflected $1.1 billion of additional construction capital costs incurred through June 30, 2022. Georgia Power expects to file its twenty-eighth VCM report with the Georgia PSC on February 16, 2023, which will reflect the revised capital cost forecast described above and $461 million of construction capital costs incurred from July 1, 2022 through December 31, 2022.

The ultimate outcome of these matters cannot be determined at this time.

See Note 17 under "Georgia Power – Nuclear Construction" for additional information.

Mississippi Power

Mississippi Power's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. Mississippi Power's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are expected to be recovered through Mississippi Power's base rates.

2019 Base Rate Case

In 2020, the Mississippi PSC approved a settlement agreement between Mississippi Power and the Mississippi Public Utilities Staff related to Mississippi Power's base rate case filed in 2019 (Mississippi Power Rate Case Settlement Agreement).

Under the terms of the Mississippi Power Rate Case Settlement Agreement, annual retail rates decreased approximately $16.7 million, or 1.85%, effective for the first billing cycle of April 2020, based on a test year period of January 1, 2020 through December 31, 2020, a 53% average equity ratio, an allowed maximum actual equity ratio of 55% by the end of 2020, and a 7.57% return on investment.

Additionally, the Mississippi Power Rate Case Settlement Agreement: (i) established common amortization periods of four years for regulatory assets and three years for regulatory liabilities included in the approved revenue requirement, including those related to unprotected deferred income taxes; (ii) established new depreciation rates reflecting an annual increase in depreciation of approximately $10 million; and (iii) excluded certain compensation costs totaling approximately $3.9 million. It also eliminated separate rates for costs associated with Plant Ratcliffe and energy efficiency initiatives and includes such costs in the PEP, ECO Plan, and ad valorem tax adjustment factor, as applicable.

Performance Evaluation Plan

Mississippi Power's retail base rates generally are set under the PEP, a rate plan approved by the Mississippi PSC. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, PEP includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed ROE. PEP measures

Mississippi Power's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). Typically, two PEP filings are made for each calendar year: the PEP projected filing in March of the current year and the PEP lookback filing in March of the subsequent year. The annual PEP projected filings utilize a historic test year adjusted for "known and measurable" changes and discounted cash flow and regression formulas to determine base ROE. The PEP lookback filing reflects the actual revenue requirement.

Pursuant to a Mississippi PSC-approved settlement agreement between Mississippi Power and the MPUS, Mississippi Power was not required to make any PEP filings for the regulatory year 2020.

In June 2021 and June 2022, the Mississippi PSC approved Mississippi Power's annual retail PEP filings, resulting in annual increases in revenues of approximately $16 million, or 1.8%, and $18 million, or 1.9%, respectively, effective with the first billing cycle of April 2021 and April 2022, respectively.

Integrated Resource Plan

In 2020, the Mississippi PSC issued an order requiring Mississippi Power to incorporate into its 2021 IRP a schedule of early or anticipated retirement of 950 MWs of fossil-steam generation by year-end 2027 to reduce Mississippi Power's excess reserve margin. The order stated that Mississippi Power will be allowed to defer any retirement-related costs as regulatory assets for future recovery.

In September 2021, the Mississippi PSC concluded its review of Mississippi Power's 2021 IRP. The 2021 IRP included a schedule to retire Plant Watson Unit 4 (268 MWs) and Mississippi Power's 40% ownership interest in Plant Greene County Units 1 and 2 (103 MWs each) in December 2023, 2025, and 2026, respectively, consistent with each unit's remaining useful life in the most recent approved depreciation studies. In addition, the schedule reflects the early retirement of Mississippi Power's 50% undivided ownership interest in Plant Daniel Units 1 and 2 (502 MWs) by the end of 2027. The Plant Greene County unit retirements require the completion by Alabama Power of transmission and system reliability improvements, as well as agreement by Alabama Power. Mississippi Power is scheduled to file its next IRP in April 2024.

The remaining net book value of Plant Daniel Units 1 and 2 was approximately $499 million at December 31, 2022 and Mississippi Power is continuing to depreciate these units using the current approved rates through the end of 2027. Mississippi Power expects to reclassify the net book value remaining at retirement, which is expected to total approximately $397 million, to a regulatory asset to be amortized over a period to be determined by the Mississippi PSC in future proceedings, consistent with the 2020 order. The Plant Watson and Greene County units are expected to be fully depreciated upon retirement. The ultimate outcome of these matters cannot be determined at this time. See Note 3 under "Other Matters – Mississippi Power" for additional information on Plant Daniel Units 1 and 2.

Environmental Compliance Overview Plan

In accordance with a 2011 accounting order from the Mississippi PSC, Mississippi Power has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations.

In June 2021, the Mississippi PSC approved Mississippi Power's ECO Plan filing for 2021, resulting in a decrease in revenues of approximately $9 million annually effective with the first billing cycle of July 2021.

On April 5, 2022, the Mississippi PSC approved Mississippi Power's ECO Plan filing for 2022, resulting in an increase in revenues of approximately $1 million annually. The rate increase became effective with the first billing cycle of May 2022.

On February 14, 2023, Mississippi Power submitted its ECO Plan filing for 2023 indicating no change in retail rates. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

Mississippi Power annually establishes, and is required to file for an adjustment to, the retail fuel cost recovery factor that is approved by the Mississippi PSC. The Mississippi PSC approved a decrease of $24 million effective in February 2020 and increases of $2 million and $43 million effective in February 2021 and 2022, respectively. On November 15, 2022, Mississippi Power filed a request with the Mississippi PSC to increase retail fuel revenues by $25 million annually effective with the first billing cycle of February 2023 and an additional $25 million annually effective with the first billing cycle of June 2023. On January 10, 2023, the Mississippi PSC voted to defer approval of the filing. Mississippi Power is allowed to maintain current billing rates and continue accruing its weighted-average cost of capital on any under or over fuel recovery balance. The ultimate outcome of this matter cannot be determined at this time.

At December 31, 2022 and 2021, under recovered retail fuel costs totaled approximately $1 million and $4 million, respectively, and were included in other customer accounts receivable on Southern

At December 31, 2022 and 2021, under recovered retail fuel costs totaled approximately $1 million and $4 million, respectively, and were included in other customer accounts receivable on Southern Company's and Mississippi Power's balance sheets.

Mississippi Power has wholesale MRA and Market Based (MB) fuel cost recovery factors. Effective with the first billing cycles for January 2021, 2022, and 2023, annual revenues under the wholesale MRA fuel rate decreased $5 million, increased $11 million, and increased $22 million, respectively. The wholesale MB fuel rate did not change materially in any period presented. At December 31, 2022 and 2021, under recovered wholesale fuel costs were $6 million and $1 million, respectively.

Mississippi Power's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on Mississippi Power's revenues or net income but will affect operating cash flows.

Ad Valorem Tax Adjustment

Mississippi Power annually establishes an ad valorem tax adjustment factor that is approved by the Mississippi PSC. Effective with the first billing cycle of April 2020, May 2021, and July 2022, the Mississippi PSC approved increases in annual revenues collected through the ad valorem tax adjustment factor of $10 million, $28 million, and $5 million, respectively. The 2021 increase included approximately $19 million of ad valorem taxes previously recovered through PEP in accordance with the Mississippi Power Rate Case Settlement Agreement.

System Restoration Rider

Mississippi Power carries insurance for the cost of certain types of damage to generation plants and general property. However, Mississippi Power is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, Mississippi Power accrues for the cost of such damage through an annual expense accrual which is credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. Every year, the Mississippi PSC, the MPUS, and Mississippi Power agree on SRR revenue level(s).

Mississippi Power's net retail SRR accrual, which includes carrying costs and amortization of related excess deferred income tax benefits, was $6.9 million in 2022, $(1.8) million in 2021, and $0.8 million in 2020. At December 31, 2022 and 2021, the retail property damage reserve balance was $37 million and $31 million, respectively.

In December 2021, the Mississippi PSC approved Mississippi Power's annual SRR filing, which requested an increase in retail revenues of approximately $9 million annually effective with the first billing cycle of March 2022. The Mississippi PSC also established $8 million as the minimum annual accrual amount until a target property damage reserve balance of $75 million is met. In the event the expected annual charges exceed the annual accrual or the target balance has been met, Mississippi Power and the Mississippi PSC will determine the appropriate change to the annual accrual. Additionally, if PEP earnings are above a certain threshold, Mississippi Power has the ability to apply any required PEP refund as an additional accrual to the property damage reserve in lieu of customer refunds.

On February 14, 2023, Mississippi Power submitted its annual SRR filing to the Mississippi PSC, which indicated no change in retail rates. The filing includes a request to increase the minimum annual accrual from $8 million to $12 million. The ultimate outcome of this matter cannot be determined at this time.

Reliability Reserve Accounting Order

On December 6, 2022, the Mississippi PSC approved an accounting order authorizing Mississippi Power to create a reliability reserve for the purpose of deferring generation, transmission, and distribution reliability-related expenditures for use in a future year. Mississippi Power may make accruals to the reliability reserve each year after meeting with the MPUS and Mississippi PSC staff. Mississippi Power will provide annually, through its capital plan, energy delivery plan, or PEP filing, any amounts to be charged against the reliability reserve during the current year. At December 31, 2022, Mississippi Power accrued $25 million to the reliability reserve.

Software Accounting Order

On December 6, 2022, the Mississippi PSC approved an accounting order authorizing Mississippi Power to establish a regulatory asset for certain operations and maintenance expenditures related to major technology projects. The recovery period for this regulatory asset will be determined in Mississippi Power's annual PEP filing process. Mississippi Power will begin deferring these costs in 2023.

Municipal and Rural Associations Tariff

Mississippi Power provides wholesale electric service to Cooperative Energy, East Mississippi Electric Power Association, and the City of Collins, all located in southeastern Mississippi, under a long-term, cost-based, FERC-regulated MRA tariff.

In 2017, Mississippi Power and Cooperative Energy executed, and the FERC accepted, a Shared Service Agreement (SSA), as part of the MRA tariff, under which Mississippi Power and Cooperative Energy share in providing electricity to the Cooperative Energy delivery points under the tariff. On August 26, 2022, the FERC accepted an amended SSA between Mississippi Power and Cooperative Energy, effective July 1, 2022, under which Cooperative Energy will continue to decrease its use of Mississippi Power's generation services under the MRA tariff up to 2.5% annually through 2035. At December 31, 2022, Mississippi Power is serving approximately 400 MWs of Cooperative Energy's annual demand. Beginning in 2036, Cooperative Energy will provide 100% of its electricity requirements at the MRA delivery points under the tariff. Neither party has the option to cancel the amended SSA.

On July 15, 2022, Mississippi Power filed a request with the FERC for a $23 million increase in annual wholesale base revenues under the MRA tariff. Cooperative Energy filed a complaint with the FERC challenging the new rates. On September 13, 2022, the FERC issued an order that accepted Mississippi Power's request effective September 14, 2022, subject to refund, and established hearing and settlement judge procedures. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

Utility Regulation and Rate Design

The natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies. Rates charged to customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable ROE.

As a result of operating in a deregulated environment, Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically. The Marketers add these fixed charges when billing customers. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. Southern Company Gas has various mechanisms, such as weather and revenue normalization mechanisms and weather derivative instruments, that limit exposure to weather changes within typical ranges in these utilities' respective service territories.

In addition to natural gas cost recovery mechanisms, other cost recovery mechanisms and regulatory riders, which vary by utility, allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation, energy efficiency plans, and bad debts. In traditional rate designs, utilities recover a significant portion of the fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by customers. With the exception of Chattanooga Gas, the natural gas distribution utilities have decoupled regulatory mechanisms that Southern Company Gas believes encourage conservation by separating the recoverable amount of these fixed costs from the amounts of natural gas used by customers. See "Rate Proceedings" herein for additional information. Also see "Infrastructure Replacement Programs and Capital Projects" herein for additional information regarding infrastructure replacement programs at certain of the natural gas distribution utilities.

The following table provides regulatory information for Southern Company Gas' natural gas distribution utilities:

	Nicor Gas	Atlanta Gas Light	Virginia Natural Gas	Chattanooga Gas
Authorized ROE at December 31, 2022	9.75%	10.25%	9.50%	9.80%
Weather normalization mechanisms[a]			✓	✓
Decoupled, including straight-fixed-variable rates[b]	✓	✓	✓	
Regulatory infrastructure program rates[c]	✓	✓	✓	✓
Bad debt rider[d]	✓		✓	✓
Energy efficiency plan[e]	✓		✓	

Annual base rate adjustment mechanism[f]		✓		✓
Year of last base rate case decision	2021	2019	2021	2018

(a) Designed to help stabilize operating results by allowing recovery of costs in the event of unseasonal weather, but are not direct offsets to the potential impacts on earnings of weather and customer consumption.

(b) Allows for recovery of fixed customer service costs separately from assumed natural gas volumes used by customers and provides a benchmark level of revenue for recovery.

(c) Programs that update or expand distribution systems and LNG facilities. Atlanta Gas Light's infrastructure program, System Reinforcement Rider, is effective for 2022 through 2024. See "Rate Proceedings – Atlanta Gas Light" herein for additional information. Chattanooga Gas' pipeline replacement program costs are recovered through its annual base rate review mechanism.

(d) The recovery (refund) of bad debt expense over (under) an established benchmark expense. The gas portion of bad debt expense is recovered through purchased gas adjustment mechanisms. Nicor Gas also has a rider to recover the non-gas portion of bad debt expense.

(e) Recovery of costs associated with plans to achieve specified energy savings goals.

(f) Regulatory mechanism allowing annual adjustments to base rates up or down based on authorized ROE and/or ROE range.

Infrastructure Replacement Programs and Capital Projects

In addition to capital expenditures recovered through base rates by each of the natural gas distribution utilities, Nicor Gas and Virginia Natural Gas have separate rate riders that provide timely recovery of capital expenditures for specific infrastructure replacement programs. Total capital expenditures incurred during 2022 for gas distribution operations were $1.5 billion.

The following table and discussions provide updates on the infrastructure replacement programs and capital projects at the natural gas distribution utilities at December 31, 2022. These programs are risk-based and designed to update and replace cast iron, bare steel, and mid-vintage plastic materials or expand Southern Company Gas' distribution systems to improve reliability and meet operational flexibility and growth.

Utility	Program	Recovery	Expenditures in 2022	Expenditures Since Project Inception	Pipe Installed Since Project Inception	Scope of Program	Program Duration	Last Year of Program
			(in millions)		*(miles)*	*(miles)*	*(years)*	
Nicor Gas	Investing in Illinois[*]	Rider	$ 437	$ 2,945	1,297	1,854	9	2023
Virginia Natural Gas	Steps to Advance Virginia's Energy (SAVE)	Rider	69	411	525	695	13	2024
Atlanta Gas Light	System Reinforcement Rider	Rider	76	76	10	N/A	3	2024
Chattanooga Gas	Pipeline Replacement Program	Rate Base	5	7	5	73	7	2027
Total			$ 587	$ 3,439	1,837	2,622		

* Includes replacement of pipes, compressors, and transmission mains along with other improvements such as new meters. Scope of program miles is an estimate and subject to change. Recovery of program costs is described under "Nicor Gas" herein.

Nicor Gas

Illinois legislation allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system through 2023 and stipulates that rate increases to customers as a result of any infrastructure investments shall not exceed a cumulative annual average of 4.0% or, in any given year, 5.5% of base rate revenues. In 2014, the Illinois Commission approved the nine-year regulatory infrastructure program, Investing in Illinois, subject to annual review. In accordance with orders from the Illinois Commission, Nicor Gas recovers program costs incurred through a separate rider and base rates. The Illinois Commission's approval of Nicor Gas' rate case in November 2021 included recovery of program costs through December 31, 2021. See "Rate Proceedings – Nicor Gas" herein for additional information. Nicor Gas' capital expenditures related to qualifying projects under the Investing in Illinois program totaled $408 million and $389 million in 2021 and 2020, respectively.

Virginia Natural Gas

The Steps to Advance Virginia's Energy (SAVE) program, an accelerated infrastructure replacement program, allows Virginia Natural Gas to continue replacing aging pipeline infrastructure through 2024. The program includes authorized annual investments of $50 million in 2020, $60 million in 2021, and $70 million in each year from 2022 through 2024, with a total potential variance of up to $5 million allowed for the program, for a maximum total investment over the six-year term (2019 through 2024) of $365 million. Virginia Natural Gas' capital expenditures under the SAVE program totaled $51 million and $49 million in 2021 and 2020, respectively.

The SAVE program is subject to annual review by the Virginia Commission. In accordance with the base rate case approved by the Virginia Commission in 2021, Virginia Natural Gas is recovering program costs incurred prior to November 1, 2020 through base rates. Program costs incurred subsequent to November 1, 2020 are currently being recovered through a separate rider and are subject to future base rate case proceedings.

Atlanta Gas Light

In 2019, the Georgia PSC approved the continuation of GRAM as part of Atlanta Gas Light's 2019 rate case order. Various infrastructure programs previously authorized by the Georgia PSC, including the Integrated Vintage Plastic Replacement Program to replace aging plastic pipe and the Integrated System Reinforcement Program to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, continue under GRAM and the recovery of and return on the infrastructure program investments are included in annual base rate adjustments. The amounts to be recovered through rates related to allowed, but not incurred, costs have been recognized in an unrecognized ratemaking amount that is not reflected on the balance sheets. These allowed costs are primarily the equity return on the capital investment under the infrastructure programs in place prior to GRAM and are being recovered through GRAM and base rates until the earlier of the full recovery of the related under recovered amount or December 31, 2025. The under recovered balance at December 31, 2022 was $68 million, including $35 million of unrecognized equity

return. The Georgia PSC reviews Atlanta Gas Light's performance annually under GRAM. See "Unrecognized Ratemaking Amounts" herein for additional information.

Atlanta Gas Light and the staff of the Georgia PSC previously agreed to a variation of the Integrated Customer Growth Program to extend pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. A separate tariff provides recovery of up to $15 million annually for strategic economic development projects approved by the Georgia PSC.

See "Rate Proceedings – Atlanta Gas Light" herein for additional information regarding the Georgia PSC's November 2021 approval of Atlanta Gas Light's GRAM filing and Integrated Capacity and Delivery Plan. The Georgia PSC also approved a new System Reinforcement Rider for authorized large pressure improvement and system reliability projects, which is expected to recover related capital investments totaling $286 million for the years 2022 through 2024, of which $76 million was incurred in 2022.

Chattanooga Gas

In June 2021, the Tennessee Public Utilities Commission approved Chattanooga Gas' pipeline replacement program to replace approximately 73 miles of distribution main over a seven-year period. The estimated total cost of the program is $118 million, which will be recovered through Chattanooga Gas' annual base rate review mechanism.

Natural Gas Cost Recovery

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized by the relevant regulatory agencies in the states in which they serve to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. The natural gas distribution utilities defer or accrue the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. Changes in the billing factor will not have a significant effect on Southern Company's or Southern Company Gas' net income, but will affect cash flows. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain natural gas inventory for the Marketers in Georgia and recovers the cost through recovery mechanisms approved by the Georgia PSC. At December 31, 2022, the under recovered balance was $108 million, which was included in natural gas cost under recovery on Southern Company's and Southern Company Gas' balance sheets. At December 31, 2021, the under recovered balance was $473 million, $266 million of which was included in natural gas cost under recovery and $207 million of which was included in other regulatory assets, deferred on Southern Company's and Southern Company Gas' balance sheets.

Rate Proceedings

Nicor Gas

In November 2021, the Illinois Commission approved a $240 million annual base rate increase effective November 24, 2021. The base rate increase included $94 million related to the recovery of program costs under the Investing in Illinois program and was based on a ROE of 9.75% and an equity ratio of 54.5%.

On January 3, 2023, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $321 million increase in annual base rate revenues, including $59 million related to the recovery of investments under the Investing in Illinois program through December 31, 2023. The requested increase is based on a projected test year for the 12-month period ending December 31, 2024, a return on equity of 10.35%, and an equity ratio of 54.5%. Further, Nicor Gas is seeking to recover an additional $32 million under three proposed riders related to recovery of vehicle fuel costs, company use gas, and customer payment fees. The Illinois Commission is expected to rule on the requested increase within the 11-month statutory time limit, after which rate adjustments will be effective. The ultimate outcome of this matter cannot be determined at this time.

Atlanta Gas Light

The Georgia PSC evaluates Atlanta Gas Light's earnings against a ROE range of 10.05% to 10.45%, with disposition of any earnings above 10.45% to be determined by the Georgia PSC. Additionally, the Georgia PSC allows inclusion in base rates of the recovery of and return on the infrastructure program investments, including, but not limited to, GRAM adjustments. GRAM filing rate adjustments are based on an authorized ROE of 10.25%. GRAM adjustments for 2021 could not exceed 5% of 2020 base rates. The 5% limitation does not set a precedent in any future rate proceedings by Atlanta Gas Light.

In 2020, Atlanta Gas Light filed its annual GRAM filing with the Georgia PSC requesting an annual base rate increase of $37.6 million based on the projected 12-month period beginning January 1, 2021, which did not exceed the 5% limitation established by the Georgia PSC. Rates went into effect on January 1, 2021.

In February 2021, the Georgia PSC approved a stipulation between Atlanta Gas Light and the Georgia PSC staff establishing a long-range comprehensive planning process. Under the terms of the stipulation, Atlanta Gas Light was required to develop and file at least triennially an Integrated Capacity and Delivery Plan (i-CDP). Each i-CDP will include a 10-year forecast of interstate and intrastate capacity asset requirements, including a detailed plan for the first three years consistent with Atlanta Gas Light's current capacity supply plan, and a 10-year projection of capital budgets and related operations and maintenance spending. Recovery of the related revenue requirements will be included in either subsequent annual GRAM filings or a new System Reinforcement Rider for authorized large pressure improvement and system reliability projects.

In April 2021, Atlanta Gas Light filed its first i-CDP with the Georgia PSC, which included a series of ongoing and proposed pipeline safety, reliability, and growth programs for the next 10 years (2022 through 2031), as well as the required capital investments and related costs to implement the programs. The i-CDP reflected capital investments totaling approximately $0.5 billion to $0.6 billion annually.

In November 2021, the Georgia PSC approved a joint stipulation agreement between Atlanta Gas Light and the staff of the Georgia PSC, under which, for the years 2022 through 2024, Atlanta Gas Light will incrementally reduce its combined GRAM and System Reinforcement Rider request by 10% through Atlanta Gas Light's GRAM mechanism, which resulted in a reduction of $5 million for 2022 and $7 million for 2023. The stipulation agreement also provided for $1.7 billion of total capital investment for the years 2022 through 2024.

Also in November 2021, the Georgia PSC approved Atlanta Gas Light's amended annual GRAM filing, which resulted in an annual rate increase of $43 million effective January 1, 2022.

On December 20, 2022, the Georgia PSC approved Atlanta Gas Light's annual GRAM filing, which resulted in an annual rate increase of $53 million effective January 1, 2023.

Virginia Natural Gas

In September 2021, the Virginia Commission approved a stipulation agreement related to Virginia Natural Gas' 2020 general rate case filing, which allowed for a $43 million increase in annual base rate revenues, including $14 million related to the recovery of investments under the SAVE program, based on a ROE of 9.5% and an equity ratio of 51.9%. Interim rate adjustments became effective as of November 1, 2020, subject to refund, based on Virginia Natural Gas' original request for an increase of approximately $50 million. Refunds to customers related to the difference between the approved rates and the interim rates were completed during the fourth quarter 2021.

On August 1, 2022, Virginia Natural Gas filed a general base rate case with the Virginia Commission seeking an increase in annual base rate revenues of $69 million, including $15 million related to the recovery of investments under the SAVE program, primarily to recover investments and increased costs associated with infrastructure, technology, and workforce development. The requested increase is based on a projected 12-month period beginning January 1, 2023, a ROE of 10.35%, and an equity ratio of 53.2%. Rate adjustments became effective January 1, 2023, subject to refund. The Virginia Commission is expected to rule on the requested increase in the third quarter 2023. The ultimate outcome of this matter cannot be determined at this time.

Unrecognized Ratemaking Amounts

The following table illustrates Southern Company Gas' authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain regulatory infrastructure programs. These amounts will be recognized as revenues in Southern Company Gas' financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

	December 31, 2022	December 31, 2021
	(in millions)	
Atlanta Gas Light	**$ 35**	$ 47
Virginia Natural Gas	**10**	10
Chattanooga Gas	**2**	4
Nicor Gas	**3**	—
Total	**$ 50**	$ 61

4. REVENUE FROM CONTRACTS WITH CUSTOMERS

The Registrants generate revenues from a variety of sources, some of which are not accounted for as revenue from contracts with customers, such as leases, derivatives, and certain cost recovery mechanisms. See Note 1 under "Revenues" for additional

information on the revenue policies of the Registrants. See Notes 9 and 14 for additional information on revenue accounted for under lease and derivative accounting guidance, respectively.

The following table disaggregates revenue from contracts with customers for the periods presented:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022						
Operating revenues						
Retail electric revenues						
Residential	**$ 6,604**	**$ 2,638**	**$ 3,664**	**$ 302**	**$ —**	**$ —**
Commercial	**5,369**	**1,685**	**3,385**	**299**	**—**	**—**
Industrial	**3,764**	**1,507**	**1,921**	**336**	**—**	**—**
Other	**102**	**14**	**79**	**9**	**—**	**—**
Total retail electric revenues	**15,839**	**5,844**	**9,049**	**946**	**—**	**—**
Natural gas distribution revenues						
Residential	**2,843**	**—**	**—**	**—**	**—**	**2,843**
Commercial	**763**	**—**	**—**	**—**	**—**	**763**
Transportation	**1,186**	**—**	**—**	**—**	**—**	**1,186**
Industrial	**84**	**—**	**—**	**—**	**—**	**84**

Other	**342**	**—**	**—**	**—**	**—**	**342**
Total natural gas distribution revenues	**5,218**	**—**	**—**	**—**	**—**	**5,218**
Wholesale electric revenues						
PPA energy revenues	**2,274**	**489**	**130**	**16**	**1,673**	**—**
PPA capacity revenues	**596**	**194**	**47**	**4**	**356**	**—**
Non-PPA revenues	**250**	**200**	**30**	**690**	**740**	**—**
Total wholesale electric revenues	**3,120**	**883**	**207**	**710**	**2,769**	**—**
Other natural gas revenues						
Gas marketing services	**636**	**—**	**—**	**—**	**—**	**636**
Other natural gas revenues	**51**	**—**	**—**	**—**	**—**	**51**
Total natural gas revenues	**687**	**—**	**—**	**—**	**—**	**687**
Other revenues	**1,077**	**194**	**446**	**47**	**36**	**—**
Total revenue from contracts with customers	**25,941**	**6,921**	**9,702**	**1,703**	**2,805**	**5,905**
Other revenue sources[(a)]	**3,338**	**896**	**1,882**	**(9)**	**564**	**57**
Total operating revenues	**$ 29,279**	**$ 7,817**	**$ 11,584**	**$ 1,694**	**$ 3,369**	**$ 5,962**
2021						
Operating revenues						
Retail electric revenues						
Residential	$ 6,207	$ 2,467	$ 3,471	$ 269	$ —	$ —
Commercial	4,877	1,600	3,010	267	—	—
Industrial	3,067	1,386	1,391	290	—	—
Other	93	17	68	8	—	—
Total retail electric revenues	14,244	5,470	7,940	834	—	—
Natural gas distribution revenues						
Residential	1,799	—	—	—	—	1,799
Commercial	470	—	—	—	—	470
Transportation	1,038	—	—	—	—	1,038
Industrial	49	—	—	—	—	49
Other	269	—	—	—	—	269
Total natural gas distribution revenues	3,625	—	—	—	—	3,625
Wholesale electric revenues						
PPA energy revenues	1,122	184	95	11	854	—
PPA capacity revenues	493	115	55	5	323	—
Non-PPA revenues	236	170	21	401	398	—
Total wholesale electric revenues	1,851	469	171	417	1,575	—
Other natural gas revenues						
Wholesale gas services	2,168	—	—	—	—	2,168
Gas marketing services	464	—	—	—	—	464
Other natural gas revenues	36	—	—	—	—	36
Total other natural gas revenues	2,668	—	—	—	—	2,668
Other revenues	1,075	202	452	31	30	—
Total revenue from contracts with customers	23,463	6,141	8,563	1,282	1,605	6,293
Other revenue sources[(a)]	3,349	272	697	40	611	1,786
Other adjustments[(b)]	(3,699)	—	—	—	—	(3,699)
Total operating revenues	$ 23,113	$ 6,413	$ 9,260	$ 1,322	$ 2,216	$ 4,380
2020						
Operating revenues						
Retail electric revenues						
Residential	$ 6,113	$ 2,377	$ 3,476	$ 260	$ —	$ —
Commercial	4,699	1,512	2,933	254	—	—
Industrial	2,775	1,293	1,197	285	—	—
Other	90	21	60	9	—	—
Total retail electric revenues	13,677	5,203	7,666	808	—	—
Natural gas distribution revenues						
Residential	1,338	—	—	—	—	1,338
Commercial	340	—	—	—	—	340
Transportation	971	—	—	—	—	971
Industrial	30	—	—	—	—	30
Other	209	—	—	—	—	209
Total natural gas distribution revenues	2,888	—	—	—	—	2,888
Wholesale electric revenues						
PPA energy revenues	735	133	42	9	570	—
PPA capacity revenues	454	108	50	3	296	—
Non-PPA revenues	210	43	10	311	239	—
Total wholesale electric revenues	1,399	284	102	323	1,105	—
Other natural gas revenues						
Wholesale gas services	1,727	—	—	—	—	1,727
Gas marketing services	391	—	—	—	—	391
Other natural gas revenues	33	—	—	—	—	33
Total other natural gas revenues	2,151	—	—	—	—	2,151

Other revenues	982	159	447	26	14	—
Total revenue from contracts with customers	21,097	5,646	8,215	1,157	1,119	5,039
Other revenue sources[(a)]	3,764	184	94	15	614	2,881
Other adjustments[(b)]	(4,486)	—	—	—	—	(4,486)
Total operating revenues	$ 20,375	$ 5,830	$ 8,309	$ 1,172	$ 1,733	$ 3,434

(a) Other revenue sources relate to revenues from customers accounted for as derivatives and leases, alternative revenue programs at Southern Company Gas, and cost recovery mechanisms and revenues that meet other scope exceptions for revenues from contracts with customers at the traditional electric operating companies.

(b) Other adjustments relate to the cost of Southern Company Gas' energy and risk management activities. Wholesale gas services revenues are presented net of the related costs of those activities on the statement of income. See Notes 15 and 16 under "Southern Company Gas" for information on the sale of Sequent and components of wholesale gas services' operating revenues, respectively.

Contract Balances

The following table reflects the closing balances of receivables, contract assets, and contract liabilities related to revenues from contracts with customers at December 31, 2022 and 2021:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Accounts Receivable						
At December 31, 2022	$ 3,123	$ 696	$ 922	$ 92	$ 237	$ 1,107
At December 31, 2021	2,504	589	736	73	149	753
Contract Assets						
At December 31, 2022	$ 156	$ 2	$ 89	$ —	$ —	$ —
At December 31, 2021	117	2	63	—	1	—
Contract Liabilities						
At December 31, 2022	$ 45	$ 4	$ 9	$ —	$ 1	$ —
At December 31, 2021	57	4	14	—	1	—

At December 31, 2022 and 2021, Georgia Power had contract assets primarily related to retail customer fixed bill programs, where the payment is contingent upon Georgia Power's continued performance and the customer's continued participation in the program over a one-year contract term, and unregulated service agreements, where payment is contingent on project completion. Contract liabilities for Georgia Power relate to cash collections recognized in advance of revenue for unregulated service agreements. Southern Company's unregulated distributed generation business had contract assets of $65 million and $50 million at December 31, 2022 and 2021, respectively, and contract liabilities of $32 million and $39 million at December 31, 2022 and 2021, respectively, for outstanding performance obligations.

Revenues recognized in 2022 and 2021, which were included in contract liabilities at December 31, 2021 and December 31, 2020, respectively, were $36 million and $29 million, respectively, for Southern Company and immaterial for the other Registrants.

Remaining Performance Obligations

The Subsidiary Registrants have long-term contracts with customers in which revenues are recognized as performance obligations are satisfied over the contract term. For the traditional electric operating companies and Southern Power, these contracts primarily relate to PPAs whereby electricity and generation capacity are provided to a customer. The revenue recognized for the delivery of electricity is variable; however, certain PPAs include a fixed payment for fixed generation capacity over the term of the contract. For Southern Company Gas, these contracts involve energy infrastructure enhancement and upgrade projects for certain governmental customers. Southern Company's unregulated distributed generation business also has partially satisfied performance obligations related to certain fixed price contracts. Revenues from contracts with customers related to these performance obligations remaining at December 31, 2022 are expected to be recognized as follows:

	2023	2024	2025	2026	2027	Thereafter
			(in millions)			
Southern Company	$ 640	$ 483	$ 332	$ 311	$ 315	$ 2,076
Alabama Power	24	7	6	—	—	—
Georgia Power	74	39	22	11	10	10
Southern Power	355	345	302	303	310	2,077
Southern Company Gas	34	29	—	—	—	—

Revenue expected to be recognized for performance obligations remaining at December 31, 2022 was immaterial for Mississippi Power.

5. PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment is stated at original cost or fair value at acquisition, as appropriate, less any regulatory disallowances and impairments. Original cost may include: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of equity funds used during construction.

The Registrants' property, plant, and equipment in service consisted of the following at December 31, 2022 and 2021:

At December 31, 2022:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Electric utilities:						
Generation	**$ 51,756**	**$ 15,920**	**$ 17,755**	**$ 2,826**	**$ 14,619**	**$ —**
Transmission	**14,201**	**5,658**	**7,576**	**927**	**—**	**—**
Distribution	**24,200**	**9,154**	**13,819**	**1,228**	**—**	**—**
General/other	**5,806**	**2,740**	**2,729**	**273**	**39**	**—**
Electric utilities' plant in service	**95,963**	**33,472**	**41,879**	**5,254**	**14,658**	**—**
Southern Company Gas:						
Natural gas distribution utilities transportation and distribution	**16,810**	**—**	**—**	**—**	**—**	**16,810**
Storage facilities	**1,553**	**—**	**—**	**—**	**—**	**1,553**
Other	**1,360**	**—**	**—**	**—**	**—**	**1,360**
Southern Company Gas plant in service	**19,723**	**—**	**—**	**—**	**—**	**19,723**
Other plant in service	**1,843**	**—**	**—**	**—**	**—**	**—**
Total plant in service	**$ 117,529**	**$ 33,472**	**$ 41,879**	**$ 5,254**	**$ 14,658**	**$ 19,723**

At December 31, 2021:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			

Electric utilities:						
Generation	$ 53,803	$ 16,631	$ 19,184	$ 2,791	$ 14,551	$ —
Transmission	13,406	5,334	7,132	900	—	—
Distribution	22,236	8,643	12,437	1,156	—	—
General/other	5,423	2,527	2,579	259	34	—
Electric utilities' plant in service	94,868	33,135	41,332	5,106	14,585	—
Southern Company Gas:						
Natural gas distribution utilities transportation and distribution	15,714	—	—	—	—	15,714
Storage facilities	1,315	—	—	—	—	1,315
Other	1,851	—	—	—	—	1,851
Southern Company Gas plant in service	18,880	—	—	—	—	18,880
Other plant in service	1,844	—	—	—	—	—
Total plant in service	$ 115,592	$ 33,135	$ 41,332	$ 5,106	$ 14,585	$ 18,880

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs and certain maintenance costs including those described below.

In accordance with orders from their respective state PSCs, Alabama Power and Georgia Power defer nuclear refueling outage operations and maintenance expenses to a regulatory asset when the charges are incurred. Alabama Power amortizes the costs over a subsequent 18-month period with Plant Farley's fall outage cost amortization beginning in January of the following year and spring outage cost amortization beginning in July of the same year. Georgia Power amortizes its costs over each unit's operating cycle, or 18 months for Plant Vogtle Units 1 and 2 and 24 months for Plant Hatch Units 1 and 2. Georgia Power's amortization period begins the month the refueling outage starts.

A portion of Mississippi Power's railway track maintenance costs is charged to fuel stock and recovered through Mississippi Power's fuel clause.

The portion of Southern Company Gas' non-working gas used to maintain the structural integrity of natural gas storage facilities that is considered to be non-recoverable is depreciated, while the recoverable or retained portion is not depreciated.

See Note 9 for information on finance lease right-of-use (ROU) assets, net, which are included in property, plant, and equipment.

The Registrants have deferred certain implementation costs related to cloud hosting arrangements. At December 31, 2022 and 2021, deferred cloud implementation costs, net of amortization, which are generally included in other deferred charges and assets on the Registrants' balance sheets, are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Deferred cloud implementation costs, net:						
At December 31, 2022	$ 345	$ 81	$ 108	$ 14	$ 18	$ 54
At December 31, 2021	240	54	81	11	14	35

Once a hosted software is placed into service, the related deferred costs are amortized on a straight-line basis over the remaining expected hosting arrangement term, including any renewal options that are reasonably certain of exercise. The amortization is reflected with the associated cloud hosting fees, which are generally reflected in other operations and maintenance expenses on

the Registrants' statements of income. In 2022, amortization of deferred cloud implementation costs recognized was $29 million for Southern Company, $8 million for Alabama Power, $12 million for Georgia Power, and immaterial for the other Registrants. In 2021, amortization from deferred cloud implementation costs was immaterial for all Registrants.

See Note 2 under "Regulatory Assets and Liabilities," "Alabama Power – Software Accounting Order," and "Mississippi Power – Software Accounting Order" for information on deferrals of certain other operations and maintenance costs associated with software and cloud computing projects by the traditional electric operating companies and natural gas distribution utilities, as authorized by their respective state PSCs or applicable state regulatory agencies.

Depreciation and Amortization

The traditional electric operating companies' and Southern Company Gas' depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates. The approximate rates for 2022, 2021, and 2020 are as follows:

	2022	2021	2020
Alabama Power	**2.7 %**	2.7 %	2.6 %
Georgia Power	**3.3 %**	3.3 %	3.0 %
Mississippi Power	**3.4 %**	3.6 %	3.7 %
Southern Company Gas	**2.7 %**	2.8 %	2.8 %

Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and/or other applicable state and federal regulatory agencies for the traditional electric operating companies and the natural gas distribution utilities. Effective April 1, 2020, Mississippi Power's depreciation rates were revised. Effective January 1, 2023, Alabama Power's and Georgia Power's depreciation rates were revised. See Note 2 for additional information.

When property, plant, and equipment subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the asset are retired when the related property unit is retired.

At December 31, 2022 and 2021, accumulated depreciation for Southern Company and Southern Company Gas consisted of utility plant in service totaling $34.3 billion and $33.1 billion, respectively, for Southern Company and $5.1 billion and $4.8 billion, respectively, for Southern Company Gas, as well as other plant in service totaling $963 million and $930 million, respectively, for Southern Company and $184 million and $219 million, respectively, for Southern Company Gas. Other plant in service includes the non-utility assets of Southern Company Gas, as well as, for Southern Company, certain other non-utility subsidiaries. Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives. Useful lives for Southern Company Gas's non-utility assets range from five to 12 years for transportation equipment, 30 to 75 years for storage facilities, and up to 75 years for other assets. Useful lives for the assets of Southern Company's other non-utility subsidiaries range up to 30 years.

Southern Power

Southern Power applies component depreciation, where depreciation is computed principally by the straight-line method over the estimated useful life of the asset. Certain of Southern Power's generation assets related to natural gas-fired facilities are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of, and revenues from, these assets. The primary assets in Southern Power's property, plant, and equipment are generating facilities, which generally have estimated useful lives as follows:

Southern Power Generating Facility	Useful life
Natural gas	Up to 50 years
Solar	Up to 35 years
Wind	Up to 35 years(*)

* Effective January 1, 2022, Southern Power revised the depreciable lives of its wind generating facilities from up to 30 years to up to 35 years. This revision resulted in an immaterial decrease in depreciation for 2022.

When Southern Power's depreciable property, plant, and equipment is retired, or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed and a gain or loss is recognized in the statements of income. Southern Power reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on Southern Power's net income.

Joint Ownership Agreements

At December 31, 2022, the Registrants' percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Alabama Power				
Greene County (natural gas) Units 1 and 2	60.0 % [a]	$ 193	$ 85	$ —
Plant Miller (coal) Units 1 and 2	91.8 [b]	2,148	712	13
Georgia Power				
Plant Hatch (nuclear)	50.1 % [c]	$ 1,401	$ 671	$ 62
Plant Vogtle (nuclear) Units 1 and 2	45.7 [c]	3,628	2,298	94
Plant Scherer (coal) Units 1 and 2	8.4 [c]	276	106	1
Plant Scherer (coal) Unit 3	75.0 [c]	1,317	567	6
Rocky Mountain (pumped storage)	25.4 [d]	184	153	1
Mississippi Power				
Greene County (natural gas) Units 1 and 2	40.0 % [a]	$ 125	$ 70	$ —
Plant Daniel (coal) Units 1 and 2	50.0 [e]	765	257	30
Southern Company Gas				
Dalton Pipeline (natural gas pipeline)	50.0 % [f]	$ 271	$ 23	$ —

(a) Jointly owned by Alabama Power and Mississippi Power and operated and maintained by Alabama Power.

(b) Jointly owned with PowerSouth and operated and maintained by Alabama Power.

(c) Georgia Power owns undivided interests in Plants Hatch, Vogtle Units 1 and 2, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, FP&L, and JEA. Georgia Power has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants.

(d) Jointly owned with OPC, which is the operator of the plant.

(e) Jointly owned by FP&L and Mississippi Power. In accordance with the operating agreement, Mississippi Power acts as FP&L's agent with respect to the operation and maintenance of these units. See Note 3 under "Other Matters – Mississippi Power – Plant Daniel" for additional information.

(f) Jointly owned with The Williams Companies, Inc., the Dalton Pipeline is a 115-mile natural gas pipeline that serves as an extension of the Transcontinental Gas Pipe Line Company, LLC pipeline system into northwest Georgia. Southern Company Gas leases its 50% undivided ownership for approximately $26 million annually through 2042. The lessee is responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff.

Georgia Power currently holds a 45.7% ownership interest in Plant Vogtle Units 3 and 4, which are under construction and had a CWIP balance of $9.7 billion at December 31, 2022, excluding charges recorded in 2018, 2020, 2021, and 2022 for the estimated probable loss associated with construction. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

The Registrants' proportionate share of their jointly-owned facility operating expenses is included in the corresponding operating expenses in the statements of income and each Registrant is responsible for providing its own financing.

Assets Subject to Lien

Mississippi Power provides retail service to its largest retail customer, Chevron Products Company (Chevron), at its refinery in Pascagoula, Mississippi through at least 2038 in accordance with agreements approved by the Mississippi PSC. The agreements grant Chevron a security interest in the co-generation assets located at the refinery and owned by Mississippi Power, with a lease receivable balance of $157 million at December 31, 2022, that is exercisable upon the occurrence of (i) certain bankruptcy events or (ii) other events of default coupled with specific reductions in steam output at the facility and a downgrade of Mississippi Power's credit rating to below investment grade by two of the three rating agencies. See Note 9 under "Lessor" for additional information.

See Note 8 under "Long-term Debt" for information regarding debt secured by certain assets of Georgia Power and Southern Company Gas.

6. ASSET RETIREMENT OBLIGATIONS

AROs are computed as the present value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. Each traditional electric operating company and natural gas distribution utility has received accounting guidance from its state PSC or applicable state regulatory agency allowing the continued accrual or recovery of other retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as regulatory liabilities and amounts to be recovered are reflected in the balance sheets as regulatory assets.

The ARO liabilities for the traditional electric operating companies primarily relate to facilities that are subject to the CCR Rule and the related state rules, principally ash ponds. In addition, Alabama Power and Georgia Power have retirement obligations related to the decommissioning of nuclear facilities (Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2). See "Nuclear Decommissioning" herein for additional information. Other significant AROs include various landfill sites and asbestos removal for Alabama Power, Georgia Power, and Mississippi Power and gypsum cells and mine reclamation for Mississippi Power. The ARO liability for Southern Power primarily relates to its solar and wind facilities, which are located on long-term land leases requiring the restoration of land at the end of the lease.

The traditional electric operating companies and Southern Company Gas also have identified other retirement obligations, such as obligations related to certain electric transmission and distribution facilities, certain asbestos-containing material within long-term assets not subject to ongoing repair and maintenance activities, certain wireless communication towers, the disposal of polychlorinated biphenyls in certain transformers, leasehold improvements, equipment on customer property, and property associated with the Southern Company system's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for certain retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

Southern Company and the traditional electric operating companies will continue to recognize in their respective statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance

with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the various state PSCs.

Details of the AROs included in the balance sheets are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power[*]
			(in millions)		
Balance at December 31, 2020	$ 10,684	$ 3,974	$ 6,265	$ 176	$ 95
Liabilities incurred	26	—	3	—	23
Liabilities settled	(456)	(202)	(210)	(24)	—

Accretion	407	156	236	7	5
Cash flow revisions	1,026	406	530	31	8
Balance at December 31, 2021	**$ 11,687**	**$ 4,334**	**$ 6,824**	**$ 190**	**$ 131**
Liabilities incurred	**36**	**—**	**35**	**—**	**—**
Liabilities settled	**(455)**	**(205)**	**(212)**	**(20)**	—
Accretion	**406**	**158**	**231**	**6**	**6**
Cash flow revisions	**(834)**	**—**	**(844)**	**3**	**7**
Balance at December 31, 2022	**$ 10,840**	**$ 4,287**	**$ 6,034**	**$ 179**	**$ 144**

* Included in other deferred credits and liabilities on Southern Power's consolidated balance sheets.

During 2021, Alabama Power recorded increases totaling approximately $406 million to its AROs primarily related to the CCR Rule and the related state rule based on updated estimates for post-closure costs at its ash ponds and inflation rates.

During 2021, Georgia Power refined the cost estimates related to its plans to close the ash ponds at all of its generating plants in compliance with the CCR Rule and the related state rule, including updates to estimates for inflation rates and the timing of closure activities, and recorded an increase of approximately $435 million to its AROs related to the CCR Rule and the related state rule. In December 2022, Georgia Power recorded a net decrease of approximately $780 million to its AROs related to the CCR Rule and the related state rule resulting from changes in estimates, including lower future inflation rates, higher discount rates, and timing of closure activities, as well as a change in closure methodology for one ash pond as approved in Georgia Power's 2022 IRP. See Note 2 under "Georgia Power – Integrated Resource Plans" for additional information.

During 2021, Mississippi Power recorded an increase of approximately $31 million to its AROs related to the CCR Rule based on updated estimates for the timing of closure activities, post-closure costs at one of its ash ponds, and inflation rates.

The cost estimates for AROs related to the disposal of CCR are based on information at December 31, 2022 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule and the related state rules. The traditional electric operating companies have periodically updated, and expect to continue periodically updating, their related cost estimates and ARO liabilities for each CCR unit as additional information related to these assumptions becomes available. Some of these updates have been, and future updates may be, material. The cost estimates for Alabama Power and Mississippi Power are based on closure-in-place for all ash ponds. The cost estimates for Georgia Power are based on a combination of closure-in-place for some ash ponds and closure by removal for others. Additionally, the closure designs and plans in the States of Alabama and Georgia are subject to approval by environmental regulatory agencies. Absent continued recovery of ARO costs through regulated rates, results of operations, cash flows, and financial condition for Southern Company and the traditional electric operating companies could be materially impacted. The ultimate outcome of these matters cannot be determined at this time.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in

accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third-party managers with oversight by the management of Alabama Power and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

Alabama Power and Georgia Power record the investment securities held in the Funds at fair value, as disclosed in Note 13, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, Georgia Power's Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. At December 31, 2022 and 2021, approximately $35 million and $42 million, respectively, of the fair market value of Georgia Power's Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $36 million and $43 million at December 31, 2022 and 2021, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

Investment securities in the Funds for December 31, 2022 and 2021 were as follows:

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
At December 31, 2022:			
Equity securities	$ 1,095	$ 690	$ 405
Debt securities	838	267	571
Other securities	210	168	42
Total investment securities in the Funds	$ 2,143	$ 1,125	$ 1,018
At December 31, 2021:			
Equity securities	$ 1,358	$ 849	$ 509
Debt securities	986	316	670
Other securities	197	159	38
Total investment securities in the Funds	$ 2,541	$ 1,324	$ 1,217

These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases. For Southern Company and Georgia Power, these amounts include Georgia Power's investment securities pledged to creditors and collateral received and excludes payables related to Georgia Power's securities lending program.

The fair value increases (decreases) of the Funds, including unrealized gains (losses) and reinvested interest and dividends and excluding the Funds' expenses, for 2022, 2021, and 2020 are shown in the table below.

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
Fair value increases (decreases)			
2022	$ (360)	$ (171)	$ (189)
2021	274	200	74
2020	280	142	138
Unrealized gains (losses)			
At December 31, 2022	$ (391)	$ (204)	$ (187)
At December 31, 2021	(27)	(30)	3
At December 31, 2020	220	121	99

The investment securities held in the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, approximately $14 million and $15 million at December 31, 2022 and 2021, respectively, previously recorded in internal reserves is being transferred into the Funds through 2040 as approved by the Alabama PSC.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2022 and 2021, the accumulated provisions for the external decommissioning trust funds were as follows:

	2022	2021
	(in millions)	
Alabama Power		
Plant Farley	**$ 1,125**	$ 1,324
Georgia Power		
Plant Hatch	**$ 628**	$ 757
Plant Vogtle Units 1 and 2	**382**	460
Plant Vogtle Unit 3	**8**	—
Total	**$ 1,018**	$ 1,217

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning at December 31, 2022 based on the most current studies, which were performed in 2018 for Alabama Power and in 2021 for Georgia Power, were as follows:

	Plant Farley	Plant Hatch(*)	Plant Vogtle Units 1 and 2(*)
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2076	2075	2079
		(in millions)	
Site study costs:			
Radiated structures	$ 1,234	$ 771	$ 628
Spent fuel management	387	186	170
Non-radiated structures	99	61	85
Total site study costs	$ 1,720	$ 1,018	$ 883

* Based on Georgia Power's ownership interests.

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2021. Significant assumptions used to determine these costs for ratemaking were an estimated inflation rate of 4.5% and 2.5% for Alabama Power and Georgia Power, respectively, and an estimated trust earnings rate of 7.0% and 4.5% for Alabama Power and Georgia Power, respectively. The next site study for Alabama Power is expected to be completed later in 2023.

Alabama Power's site-specific estimates of decommissioning costs for Plant Farley are updated every five years. Projections of funds are reviewed with the Alabama PSC to ensure that, over time, the deposits and earnings of the Funds will provide adequate funding to cover the site-specific costs. If necessary, Alabama Power would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

Under the 2019 ARP, Georgia Power's annual decommissioning cost for ratemaking was a total of $4 million for Plant Hatch and Plant Vogtle Units 1 and 2. Effective January 1, 2023, as approved in the 2022 ARP, there is no annual decommissioning cost for ratemaking. Any funding amount required by the NRC during the period covered by the 2022 ARP will be deferred to a regulatory asset and recovery is expected to be determined in Georgia Power's next base rate case. See Note 2 under "Georgia Power – Rate Plans – 2022 ARP" for additional information.

See Note 17 under "Georgia Power – Nuclear Decommissioning" for additional information.

7. CONSOLIDATED ENTITIES AND EQUITY METHOD INVESTMENTS

The Registrants may hold ownership interests in a number of business ventures with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE. If a venture is a VIE for which a Registrant is the primary beneficiary, the assets, liabilities, and results of operations of the entity are consolidated. The Registrants reassess the conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events.

For entities that are not determined to be VIEs, the Registrants evaluate whether they have control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under the control of a Registrant are consolidated, and entities over which a Registrant can exert significant influence, but which a Registrant does not control, are accounted for under the equity method of accounting.

Investments accounted for under the equity method are recorded within equity investments in unconsolidated subsidiaries in the balance sheets and, for Southern Company and Southern Company Gas, the equity income is recorded within earnings from equity method investments in the statements of income. See "SEGCO" and "Southern Company Gas" herein for additional information.

Southern Company

At December 31, 2022 and 2021, Southern Holdings had equity method investments totaling $112 million and $101 million, respectively, primarily related to investments in venture capital funds focused on energy and utility investments. Earnings from these investments were immaterial for all periods presented.

SEGCO

Alabama Power and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. Retirement of SEGCO's generating units is expected to occur by December 31, 2028. Alabama Power and Georgia Power account for SEGCO using the equity method; Southern Company consolidates SEGCO. The capacity of these units is sold equally to Alabama Power and Georgia Power. Alabama Power and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The share of purchased power included in purchased power, affiliates in the statements of income totaled $124 million in 2022, $75 million in 2021, and $67 million in 2020 for Alabama Power and $127 million in 2022, $77 million in 2021, and $69 million in 2020 for Georgia Power.

SEGCO paid dividends of $14 million in 2022, $14 million in 2021, and $12 million in 2020, one half of which were paid to each of Alabama Power and Georgia Power. In addition, Alabama Power and Georgia Power each recognize 50% of SEGCO's net income.

Alabama Power, which owns and operates a generating unit adjacent to the SEGCO generating units, has a joint ownership agreement with SEGCO for the ownership of an associated gas pipeline. Alabama Power owns 14% of the pipeline with the remaining 86% owned by SEGCO.

See Note 3 under "Guarantees" for additional information regarding guarantees of Alabama Power and Georgia Power related to SEGCO.

Southern Power

Southern Power

Variable Interest Entities

Southern Power has certain subsidiaries that are determined to be VIEs. Southern Power is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

SP Solar and SP Wind

SP Solar is owned by Southern Power and Global Atlantic Financial Group Limited (Global Atlantic). A wholly-owned subsidiary of Southern Power is the general partner and holds a 1% ownership interest, and another wholly-owned subsidiary of Southern Power owns a 66% ownership interest. Global Atlantic is the limited partner and holds the remaining 33% noncontrolling interest. SP Solar qualifies as a VIE since the arrangement is structured as a limited partnership and the 33% limited partner does not have substantive kick-out rights against the general partner.

At December 31, 2022 and 2021, SP Solar had total assets of $5.9 billion and $6.1 billion, respectively, total liabilities of $0.4 billion, and noncontrolling interests of $1.1 billion. Cash distributions from SP Solar are allocated 67% to Southern Power and 33% to Global Atlantic in accordance with their partnership interest percentage. Under the terms of the limited partnership agreement, distributions without limited partner consent are limited to available cash and SP Solar is obligated to distribute all such available cash to its partners each quarter. Available cash includes all cash generated in the quarter subject to the maintenance of appropriate operating reserves.

SP Wind is owned by Southern Power and three financial investors. A wholly-owned subsidiary of Southern Power owns 100% of the Class B membership interests and the three financial investors own 100% of the Class A membership interests. SP Wind qualifies as a VIE since the structure of the arrangement is similar to a limited partnership and the Class A members do not have substantive kick-out rights against Southern Power.

At December 31, 2022 and 2021, SP Wind had total assets of $2.2 billion and $2.3 billion, respectively, total liabilities of $169 million and $130 million, respectively, and noncontrolling interests of $39 million and $41 million, respectively. Under the terms of the limited liability agreement, distributions without Class A member consent are limited to available cash and SP Wind is obligated to distribute all such available cash to its members each quarter. Available cash includes all cash generated in the quarter subject to the maintenance of appropriate operating reserves. Cash distributions from SP Wind are generally allocated 60% to Southern Power and 40% to the three financial investors in accordance with the limited liability agreement.

Southern Power consolidates both SP Solar and SP Wind, as the primary beneficiary, since it controls the most significant activities of each entity, including operating and maintaining their assets. Certain transfers and sales of the assets in the VIEs are subject to partner consent and the liabilities are non-recourse to the general credit of Southern Power. Liabilities consist of customary working capital items and do not include any long-term debt.

Other Variable Interest Entities

Southern Power has other consolidated VIEs that relate to certain subsidiaries that have either sold noncontrolling interests to tax equity investors or acquired less than a 100% interest from facility developers. These entities are considered VIEs because the arrangements are structured similar to a limited partnership and the noncontrolling members do not have substantive kick-out rights.

At December 31, 2022 and 2021, the other VIEs had total assets of $1.8 billion and $1.9 billion, respectively, total liabilities of $0.2 billion and $0.3 billion, respectively, and noncontrolling interests of $0.8 billion and $0.9 billion, respectively. Under the terms of the partnership agreements, distributions of all available cash are required each month or quarter and additional distributions require partner consent.

Equity Method Investments

At December 31, 2022 and 2021, Southern Power had equity method investments in wind and battery energy storage projects totaling $49 million and $86 million, respectively. Earnings (loss) from these investments were immaterial for all periods presented. During 2022, Southern Power sold equity method investments in wind projects and received proceeds totaling $38 million. The gains associated with the sales were immaterial. Subsequent to December 31, 2022, Southern Power sold its remaining equity method investments in wind and battery energy storage projects and received proceeds of $50 million. The gains associated with the transactions were immaterial.

Southern Company Gas

Equity Method Investments

The carrying amounts of Southern Company Gas' equity method investments at December 31, 2022 and 2021 and related earnings (loss) from those investments for the years ended December 31, 2022, 2021, and 2020 were as follows:

Investment Balance	December 31, 2022	December 31, 2021
	(in millions)	
SNG	**$ 1,243**	$ 1,129
Other(*)	**33**	44
Total	**$ 1,276**	$ 1,173

* Balance at December 31, 2022 reflects an $11 million distribution received in 2022 from PennEast Pipeline.

Earnings (Loss) from Equity Method Investments	2022	2021	2020
		(in millions)	
SNG	**$ 146**	$ 127	$ 129
PennEast Pipeline(*)	**—**	(81)	7
Other	**2**	4	5
Total	**$ 148**	$ 50	$ 141

* For 2021, includes pre-tax impairment charges totaling $84 million. See "PennEast Pipeline Project" herein for additional information, including the September 2021 cancellation of the project. For 2020, earnings primarily result from AFUDC equity recorded by the project entity.

PennEast Pipeline Project

In 2014, Southern Company Gas entered into a partnership in which it holds a 20% ownership interest in the PennEast Pipeline, an interstate pipeline company formed to develop and operate an approximate 118-mile natural gas pipeline between New Jersey and Pennsylvania. In 2019, an appellate court ruled that the PennEast Pipeline does not have federal eminent domain authority over lands in which a state has property rights interests. In June 2021, the U.S. Supreme Court ruled in favor of PennEast Pipeline following a review of the appellate court decision. Southern Company Gas assesses its equity method investments for impairment whenever events or changes in circumstances indicate that the investment may be impaired. Following the U.S. Supreme Court ruling, during the second quarter 2021, Southern Company Gas management reassessed the project construction timing, including the anticipated timing for receipt of a FERC certificate and all remaining state and local permits, as well as potential challenges thereto, and performed an impairment analysis. The outcome of the analysis resulted in a pre-tax impairment charge of $82 million ($58 million after tax). In September 2021, PennEast Pipeline announced that further development of the project was no longer supported, and, as a result, all further development of the project ceased. During the third quarter 2021, Southern Company Gas recorded an additional pre-tax charge of $2 million ($2 million after tax) related to its share of the project level impairment, as well as $7 million of additional tax expense, resulting in total pre-tax charges of $84 million ($67 million after tax) during 2021 related to the project.

8. FINANCING

Long-term Debt

Details of long-term debt at December 31, 2022 and 2021 are provided in the following table:

	At December 31, 2022		Balance Outstanding at December 31,	
	Maturity	Weighted Average Interest Rate	2022	2021

	Maturity	Interest Rate	2022	2021
			(in millions)	
Southern Company				
Senior notes[a]	2023-2052	3.87%	$ 35,683	$ 33,120
Junior subordinated notes	2024-2081	4.58%	8,836	8,918
FFB loans[b]	2023-2044	2.88%	4,874	4,962
Revenue bonds[c]	2024-2062	3.25%	2,844	2,662
First mortgage bonds[d]	2023-2062	3.46%	2,275	2,100
Medium-term notes	2026-2027	7.03%	84	130
Other long-term debt	2024-2045	4.96%	167	270
Finance lease obligations[e]			314	215
Unamortized fair value adjustment			330	359
Unamortized debt premium (discount), net			(193)	(216)
Unamortized debt issuance expenses			(273)	(243)
Total long-term debt			54,941	52,277
Less: Amount due within one year			4,285	2,157
Total long-term debt excluding amount due within one year			$ 50,656	$ 50,120
Alabama Power				
Senior notes	2023-2052	3.86%	$ 9,675	$ 8,725
Revenue bonds[c]	2024-2038	3.44%	995	995
Other long-term debt	2026	5.62%	45	45
Finance lease obligations[e]			5	4
Unamortized debt premium (discount), net			(18)	(18)
Unamortized debt issuance expenses			(72)	(64)
Total long-term debt			10,630	9,687
Less: Amount due within one year			301	751
Total long-term debt excluding amount due within one year			$ 10,329	$ 8,936
Georgia Power				
Senior notes	2023-2052	3.90%	$ 7,925	$ 6,825
Junior subordinated notes	2077	5.00%	270	270
FFB loans[b]	2023-2044	2.88%	4,874	4,962
Revenue bonds[c]	2025-2062	3.13%	1,738	1,591
Other long-term debt			—	125
Finance lease obligations[e]			238	136
Unamortized debt premium (discount), net			(18)	(11)
Unamortized debt issuance expenses			(117)	(114)
Total long-term debt			14,910	13,784
Less: Amount due within one year			901	675
Total long-term debt excluding amount due within one year			$ 14,009	$ 13,109
Mississippi Power				
Senior notes	2024-2051	3.93%	$ 1,425	$ 1,425
Revenue bonds[c]	2025-2052	3.55%	111	76
Finance lease obligations[e]			17	18
Unamortized debt premium (discount), net			2	2
Unamortized debt issuance expenses			(10)	(10)
Total long-term debt			1,545	1,511
Less: Amount due within one year			1	1
Total long-term debt excluding amount due within one year			$ 1,544	$ 1,510
Southern Power				
Senior notes[a]	2023-2046	3.92%	$ 2,998	$ 3,711
Unamortized debt premium (discount), net			(5)	(6)
Unamortized debt issuance expenses			(14)	(17)
Total long-term debt			2,979	3,688
Less: Amount due within one year			290	679
Total long-term debt excluding amount due within one year			$ 2,689	$ 3,009
Southern Company Gas				
Senior notes	2023-2051	4.08%	$ 4,769	$ 4,348
First mortgage bonds[d]	2023-2062	3.46%	2,275	2,100
Medium-term notes	2026-2027	7.03%	84	130
Other long-term debt	2024-2045	3.81%	22	—
Unamortized fair value adjustment			330	359
Unamortized debt premium (discount), net			(8)	(35)
Unamortized debt issuance expenses			(30)	—
Total long-term debt			7,442	6,902
Less: Amount due within one year			400	47
Total long-term debt excluding amount due within one year			$ 7,042	$ 6,855

(a) Includes a fair value gain (loss) of $(31) million and $5 million at December 31, 2022 and 2021, respectively, related to Southern Power's foreign currency hedge on its euro-denominated senior notes.

(b) Secured by a first priority lien on (i) Georgia Power's undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. See "DOE Loan Guarantee Borrowings" herein for additional information.

(c) Revenue bond obligations represent loans to the traditional electric operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal and wastewater facilities. In some cases, the revenue bond obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of revenue bonds issued by public authorities. The traditional

electric operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

(d) Secured by substantially all of Nicor Gas' properties.

(e) Secured by the underlying lease ROU asset. See Note 9 for additional information.

Maturities of long-term debt for the next five years are as follows:

	Southern Company[a]	Alabama Power	Georgia Power[b]	Mississippi Power	Southern Power[c]	Southern Company Gas
			(in millions)			
2023	$ 4,293	$ 301	$ 901	$ 1	$ 290	$ 400
2024	2,280	23	499	201	—	—
2025	1,699	251	145	12	500	300
2026	3,726	46	445	1	964	530
2027	2,074	550	510	11	—	154

(a) See notes (b) and (c) below.

(b) Amounts include principal amortization related to the FFB borrowings; however, the final maturity date is February 20, 2044. See "DOE Loan Guarantee Borrowings" herein for additional information.

(c) Southern Power's 2026 maturities include $564 million of euro-denominated debt at the U.S. dollar denominated hedge settlement amount.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into a loan guarantee agreement in 2014 and the Amended and Restated Loan Guarantee Agreement in 2019. Under the Amended and Restated Loan Guarantee Agreement, the DOE agreed to guarantee the obligations of Georgia Power under the FFB Credit Facilities. Under the FFB Credit Facilities, Georgia Power was authorized to make term loan borrowings through the FFB in an amount up to approximately $5.130 billion, provided that total aggregate borrowings under the FFB Credit Facilities could not exceed 70% of (i) Eligible Project Costs minus (ii) approximately $1.492 billion (reflecting the amounts received by Georgia Power under the Guarantee Settlement Agreement less the related customer refunds).

In 2021, Georgia Power made the final borrowings under the FFB Credit Facilities and no further borrowings are permitted. During 2022, Georgia Power made principal amortization payments of $88 million under the FFB Credit Facilities. At December 31, 2022 and 2021, Georgia Power had $4.9 billion and $5.0 billion of borrowings outstanding under the FFB Credit Facilities, respectively.

All borrowings under the FFB Credit Facilities are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under its guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) Georgia Power's undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power's ability to grant liens on other property.

The final maturity date for each advance under the FFB Credit Facilities is February 20, 2044. Interest is payable quarterly and principal payments began in February 2020. Each borrowing under the FFB Credit Facilities bears interest at a fixed rate equal to the applicable U.S. Treasury rate at the time of the borrowing plus a spread equal to 0.375%.

Under the Amended and Restated Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facilities over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle Services Agreement or rejection of the Vogtle Services Agreement in any Westinghouse bankruptcy if Georgia Power does not maintain access to intellectual property rights under the related intellectual property licenses; (ii) termination of the Bechtel Agreement, unless the Vogtle Owners enter into a replacement agreement; (iii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC or by Georgia Power; (iv) failure of the holders of 90% of the ownership interests in Plant Vogtle Units 3 and 4 to vote to continue construction following certain schedule extensions; (v) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or Georgia Power's ability to repay the outstanding borrowings under the FFB Credit Facilities; or (vi) loss of or failure to receive necessary regulatory approvals. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facilities. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facilities. Under the FFB Credit Facilities, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.

See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

Secured Debt

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

As discussed under "Long-term Debt" herein, the Registrants had secured debt outstanding at December 31, 2022 and 2021. Each Registrant's senior notes, junior subordinated notes, revenue bond obligations, bank term loans, credit facility borrowings, and notes payable are effectively subordinated to all secured debt of each respective Registrant.

Equity Units

In May 2022, Southern Company remarketed $862.5 million aggregate principal amount of its Series 2019A Remarketable Junior Subordinated Notes due August 1, 2024 (2019A RSNs) and $862.5 million aggregate principal amount of its Series 2019B Remarketable Junior Subordinated Notes due August 1, 2027 (2019B RSNs), pursuant to the terms of its 2019 Series A Equity Units (Equity Units). In connection with the remarketing, the interest rates on the 2019A RSNs and the 2019B RSNs were reset to 4.475% and 5.113%, respectively, payable on a semi-annual basis. On August 1, 2022, the proceeds were ultimately used to settle the purchase contracts entered into as part of the Equity Units and Southern Company issued approximately 25.2 million shares of common stock and received proceeds of $1.725 billion. At December 30, 2022 and 2021, the 2019A RSNs and the 2019B RSNs are included in long-term debt on Southern Company's consolidated balance sheets.

Bank Credit Arrangements

At December 31, 2022, committed credit arrangements with banks were as follows:

	Expires						
Company	2023	2024	2025	2026	Total	Unused	Due within One Year
				(in millions)			
Southern Company parent	$ —	$ —	$ —	$ 2,000	$ 2,000	$ 1,998	$ —
Alabama Power	—	550	—	700	1,250	1,250	—
Georgia Power	—	—	—	1,750	1,750	1,726	—
Mississippi Power	—	150	125	—	275	275	—
Southern Power[a]	—	—	—	600	600	569	—
Southern Company Gas[b]	250	—	—	1,500	1,750	1,748	250
SEGCO	30	—	—	—	30	30	30
Southern Company	$ 280	$ 700	$ 125	$ 6,550	$ 7,655	$ 7,596	$ 280

(a) Does not include Southern Power Company's two $75 million continuing letter of credit facilities for standby letters of credit, of which $9 million and $5 million, respectively, was unused at December 31, 2022. In December 2022, Southern Power amended one of the $75 million letter of credit facilities, which extended the expiration date from 2023 to 2025. The second $75 million letter of credit facility also expires in 2025. Southern Power's subsidiaries are not parties to its bank credit arrangements or letter of credit facilities.

(b) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $800 million of the credit arrangement expiring in 2026. Southern Company Gas' committed credit arrangement expiring in 2026 also includes $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas. Pursuant to the multi-year credit arrangement expiring in 2026, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted. Nicor Gas is also the borrower under a $250 million credit arrangement expiring in 2023. See "Structural Considerations" herein for additional information.

The bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Registrants and Nicor Gas. Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

These bank credit arrangements, as well as the term loan arrangements of the Registrants, Nicor Gas, and SEGCO, contain covenants that limit debt levels and contain cross-acceleration or, in the case of Southern Power, cross-default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross-default provisions to other indebtedness would trigger an event of default if Southern Power defaulted on indebtedness or guarantee obligations over a specified threshold. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. Southern Company's, Southern Company Gas', and Nicor Gas' credit arrangements contain covenants that limit debt levels to 70% of total capitalization, as defined in the agreements, and the other subsidiaries' bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes junior subordinated notes and, in certain arrangements, other hybrid securities. Additionally, for Southern Company and Southern Power, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power to the extent such debt is non-recourse to Southern Power and capitalization excludes the capital stock or other equity attributable to such subsidiaries. At December 31, 2022, the Registrants, Nicor Gas, and SEGCO were in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

A portion of the unused credit with banks is allocated to provide liquidity support to the revenue bonds of the traditional electric operating companies and the commercial paper programs of the Registrants, Nicor Gas, and SEGCO. The amount of variable rate revenue bonds of the traditional electric operating companies outstanding requiring liquidity support at December 31, 2022 was approximately $1.7 billion (comprised of approximately $789 million at Alabama Power, $819 million at Georgia Power, and $69 million at Mississippi Power). In addition, at December 31, 2022, Alabama Power and Georgia Power had approximately $120 million and $288 million, respectively, of fixed rate revenue bonds outstanding that are required to be remarketed within the next 12 months.

At both December 31, 2022 and 2021, Southern Power had $106 million of cash collateral posted related to PPA requirements, which is included in other deferred charges and assets on Southern Power's consolidated balance sheets.

Notes Payable

The Registrants, Nicor Gas, and SEGCO make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above under "Bank Credit Arrangements." Southern Power's subsidiaries are not parties or obligors to its commercial paper program. Southern Company Gas maintains commercial paper programs at Southern Company Gas Capital and at Nicor Gas. Nicor Gas' commercial paper program supports working capital needs at Nicor Gas as Nicor Gas is not permitted to make money pool loans to affiliates. All of Southern Company Gas' other subsidiaries benefit from Southern Company Gas Capital's commercial paper program. See "Structural Considerations" herein for additional information.

In addition, Southern Company and certain of its subsidiaries have entered into various bank term loan agreements. Unless otherwise stated, the proceeds of these loans were used to repay existing indebtedness and for general corporate purposes, including working capital and, for the subsidiaries, their continuous construction programs.

Commercial paper and short-term bank term loans are included in notes payable in the balance sheets. Details of short-term borrowings for the applicable Registrants were as follows:

	Notes Payable at December 31, 2022		Notes Payable at December 31, 2021	
	Amount Outstanding	Weighted Average Interest Rate	Amount Outstanding	Weighted Average Interest Rate
	(in millions)		*(in millions)*	
Southern Company				
Commercial paper	**$ 809**	**4.7 %**	$ 1,140	0.3 %
Short-term bank debt	**1,800**	**5.0 %**	300	0.7 %
Total	**$ 2,609**	**4.9 %**	$ 1,440	0.4 %
Georgia Power				
Short-term bank debt	**$ 1,600**	**5.0 %**	$ —	— %
Southern Power				
Commercial paper	**$ 225**	**4.7 %**	$ 211	0.3 %
Southern Company Gas				
Commercial paper:				
Southern Company Gas Capital	**$ 285**	**4.8 %**	$ 379	0.3 %
Nicor Gas	**283**	**4.6 %**	530	0.3 %
Short-term bank debt:				
Nicor Gas	**200**	**4.9 %**	300	0.7 %
Total	**$ 768**	**4.7 %**	$ 1,209	0.4 %

See "Bank Credit Arrangements" herein for information on bank term loan covenants that limit debt levels and cross-acceleration or cross-default provisions.

Outstanding Classes of Capital Stock

Southern Company

Common Stock

Stock Issued

During 2022, Southern Company issued approximately 3.6 million shares of common stock primarily through equity compensation plans and received proceeds of approximately $83 million.

See "Equity Units" herein for additional information regarding Southern Company's issuance of approximately 25.2 million shares of common stock in August 2022.

Shares Reserved

At December 31, 2022, a total of 113 million shares were reserved for issuance pursuant to the Southern Investment Plan, employee savings plans, the Outside Directors Stock Plan, the Equity and Incentive Compensation Plan (which includes stock options and performance share units as discussed in Note 12), and an at-the-market program. Of the shares reserved, 28.9 million shares are available for awards under the Equity and Incentive Compensation Plan at December 31, 2022.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share (EPS) is attributable to awards outstanding under stock-based compensation plans. Earnings per share dilution resulting from stock-based compensation plans is determined using the treasury stock method. Shares used to compute diluted EPS were as follows:

	Average Common Stock Shares		
	2022	2021	2020
		(in millions)	
As reported shares	**1,075**	1,061	1,058
Effect of stock-based compensation	**6**	7	7
Diluted shares	**1,081**	1,068	1,065

In all years presented, an immaterial number of stock-based compensation awards was excluded from the diluted EPS calculation because the awards were anti-dilutive.

Redeemable Preferred Stock of Subsidiaries

As discussed further under "Alabama Power" herein, the preferred stock and Class A preferred stock of Alabama Power at December 31, 2021 is presented as "Redeemable Preferred Stock of Subsidiaries" on Southern Company's balance sheet in a manner consistent with temporary equity under applicable accounting standards. During 2022, Alabama Power redeemed all of its preferred stock and Class A preferred stock.

Alabama Power

Alabama Power has preferred stock, Class A preferred stock, preference stock, and common stock authorized, but only common stock outstanding at December 31, 2022.

During 2022, Alabama Power redeemed all of its preferred stock and Class A preferred stock at the redemption prices per share provided in the table below, plus accrued and unpaid dividends to the redemption date.

Preferred Stock Redeemed During 2022	Par Value/Stated Capital Per Share	Shares	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	$103.23
4.72% Preferred Stock	$100	50,000	$102.18
4.64% Preferred Stock	$100	60,000	$103.14
4.60% Preferred Stock	$100	100,000	$104.20
4.52% Preferred Stock	$100	50,000	$102.93
4.20% Preferred Stock	$100	135,115	$105.00
5.00% Class A Preferred Stock	$25	10,000,000	$25.00

Prior to being redeemed, Alabama Power's preferred stock and Class A preferred stock, without preference between classes, ranked senior to Alabama Power's common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of Alabama Power contained a feature that allowed the holders to elect a majority of Alabama Power's board of directors if preferred dividends were not paid for four consecutive quarters. Because such a potential redemption-triggering event was not solely within the control of Alabama Power, the preferred stock and Class A preferred stock at December 31, 2021 is presented as "Redeemable Preferred Stock" on Alabama Power's balance sheet in a manner consistent with temporary equity under applicable accounting standards.

Georgia Power

Georgia Power has preferred stock, Class A preferred stock, preference stock, and common stock authorized, but only common stock outstanding.

Mississippi Power

Mississippi Power has preferred stock and common stock authorized, but only common stock outstanding.

Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2022, consolidated retained earnings included $4.9 billion of undistributed retained earnings of the subsidiaries.

The traditional electric operating companies and Southern Power can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

See Note 7 under "Southern Power" for information regarding the distribution requirements for certain Southern Power subsidiaries.

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. At December 31, 2022, the amount of Southern Company Gas' subsidiary retained earnings restricted for dividend payment totaled $1.5 billion.

Structural Considerations

Since Southern Company and Southern Company Gas are holding companies, the right of Southern Company and Southern Company Gas and, hence, the right of creditors of Southern Company or Southern Company Gas to participate in any distribution of the assets of any respective subsidiary of Southern Company or Southern Company Gas, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred stockholders of such subsidiary.

Southern Company Gas' 100%-owned subsidiary, Southern Company Gas Capital, was established to provide for certain of Southern Company Gas' ongoing financing needs through a commercial paper program, the issuance of various debt, hybrid securities, and other financing arrangements. Southern Company Gas fully and unconditionally guarantees all debt issued by Southern Company Gas Capital. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize Southern Company Gas Capital for its financing needs.

Southern Power Company's senior notes, bank term loan, commercial paper, and bank credit arrangement are unsecured senior indebtedness, which rank equally with all other unsecured and unsubordinated debt of Southern Power Company. Southern Power's subsidiaries are not issuers, borrowers, or obligors, as applicable, under any of these unsecured senior debt arrangements, which are effectively subordinated to any future secured debt of Southern Power Company and any potential claims of creditors of Southern Power's subsidiaries.

9. LEASES

Lessee

The Registrants recognize leases with a term of greater than 12 months on the balance sheet as lease obligations, representing the discounted future fixed payments due, along with ROU assets that will be amortized over the term of each lease.

As lessee, the Registrants lease certain electric generating units (including renewable energy facilities), real estate/land, communication towers, railcars, and other equipment and vehicles. The major categories of lease obligations are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
At December 31, 2022						
Electric generating units[*]	$ 760	$ 59	$ 1,163	$ —	$ —	$ —
Real estate/land	885	4	54	2	542	36
Communication towers	141	2	4	—	—	23
Railcars	34	12	18	3	—	—

Other	79	4	1	21	—	1
Total	$ 1,899	$ 81	$ 1,240	$ 26	$ 542	$ 60
At December 31, 2021						
Electric generating units(*)	$ 802	$ 104	$ 1,217	$ —	$ —	$ —
Real estate/land	876	3	49	2	526	45
Communication towers	156	2	4	—	—	24
Railcars	32	10	20	2	—	—
Other	103	5	1	24	—	1
Total	$ 1,969	$ 124	$ 1,291	$ 28	$ 526	$ 70

* Amounts related to affiliate leases are eliminated in consolidation for Southern Company. See "Contracts that Contain a Lease" herein for additional information.

Real estate/land leases primarily consist of commercial real estate leases at Southern Company, Georgia Power, and Southern Company Gas and various land leases primarily associated with renewable energy facilities at Southern Power. The commercial real estate leases have remaining terms of up to 23 years while the land leases have remaining terms of up to 44 years, including renewal periods.

Communication towers are leased for the installation of equipment to provide cellular phone service to customers and to support the automated meter infrastructure programs at the traditional electric operating companies and Nicor Gas. Communication tower leases have remaining terms of up to 10 years with options to renew that could extend the terms for an additional 20 years.

Renewal options exist in many of the leases. Except as otherwise noted, the expected term used in calculating the lease obligation generally reflects only the noncancelable period of the lease as it is not considered reasonably certain that the lease will be extended. Land leases associated with renewable energy facilities at Southern Power and communication tower leases for automated meter infrastructure at Nicor Gas include renewal periods reasonably certain of exercise resulting in an expected lease term at least equal to the expected life of the renewable energy facilities and the automated meter infrastructure, respectively.

Contracts that Contain a Lease

While not specifically structured as a lease, some of the PPAs at Alabama Power and Georgia Power are deemed to represent a lease of the underlying electric generating units when the terms of the PPA convey the right to control the use of the underlying assets. Amounts recorded for leases of electric generating units are generally based on the amount of scheduled capacity payments due over the remaining term of the PPA, which varies between one and 17 years. Georgia Power has several PPAs with Southern Power that Georgia Power accounts for as leases with a lease obligation of $461 million and $521 million at December 31, 2022 and 2021, respectively. The amount paid for energy under these affiliate PPAs reflects a price that would be paid in an arm's-length transaction as reviewed and approved by the Georgia PSC. Amounts related to the affiliate PPAs are eliminated in consolidation for Southern Company.

Short-term Leases

Leases with an initial term of 12 months or less are not recorded on the balance sheet; the Registrants generally recognize lease expense for these leases on a straight-line basis over the lease term.

Residual Value Guarantees

Residual value guarantees exist primarily in railcar leases at Alabama Power and Georgia Power and the amounts probable of being paid under those guarantees are included in the lease payments. All such amounts are immaterial at December 31, 2022 and 2021.

Lease and Nonlease Components

For all asset categories, with the exception of electric generating units, gas pipelines, and real estate leases, the Registrants combine lease payments and any nonlease components, such as asset maintenance, for purposes of calculating the lease obligation and the right-of-use asset.

Balance sheet amounts recorded for operating and finance leases are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
At December 31, 2022						
Operating Leases						
Operating lease ROU assets, net (FERC Account 101.1)	$ 1,531	$ 71	$ 1,007	$ 9	$ 489	$ 57
Operating lease obligations - current (FERC Account 243)	$ 197	$ 9	$ 151	$ 4	$ 28	$ 9
Operating lease obligations - non-current (FERC Account 227)	1,388	67	851	5	514	51
Total operating lease obligations(*)	$ 1,585	$ 76	$ 1,002	$ 9	$ 542	$ 60
Finance Leases						
Finance lease ROU assets, net (FERC Account 101.1)	$ 292	$ 5	$ 205	$ 16	$ —	$ —
Finance lease obligations - current (FERC Account 243)	$ 18	$ 2	$ 16	$ 1	$ —	$ —
Finance lease obligations - non-current (FERC Account 227)	296	3	222	16	—	—
Total finance lease obligations	$ 314	$ 5	$ 238	$ 17	$ —	$ —
At December 31, 2021						
Operating Leases						
Operating lease ROU assets, net (FERC Account 101.1)	$ 1,701	$ 108	$ 1,157	$ 10	$ 479	$ 70
Operating lease obligations - current (FERC Account 243)	$ 250	$ 54	$ 156	$ 4	$ 28	$ 11
Operating lease obligations - non-current (FERC Account 227)	1,503	66	999	6	497	59
Total operating lease obligations(*)	$ 1,754	$ 121	$ 1,155	$ 10	$ 525	$ 70
Finance Leases						
Finance lease ROU assets, net (FERC Account 101.1)	$ 197	$ 4	$ 104	$ 17	$ —	$ —
Finance lease obligations - current (FERC Account 243)	$ 16	$ 1	$ 10	$ 1	$ —	$ —
Finance lease obligations - non-current (FERC Account 227)	199	3	126	17		

(FERC Account 227)	199	3	126	17	—	—
Total finance lease obligations	$ 215	$ 4	$ 136	$ 18	$ —	$ —

* Includes operating lease obligations related to PPAs at Southern Company, Alabama Power, and Georgia Power totaling $652 million, $59 million, and $952 million, respectively, at December 31, 2022 and $802 million, $104 million, and $1.11 billion, respectively, at December 31, 2021.

Impacts on the OATT formula rate related to the implementation of ASC 842 will be reversed per the FERC Accounting Guidance issues in 2018, Docket No. AI19-1-000.
If not presented separately on the Registrants' balance sheets, amounts related to leases are presented as follows: operating lease ROU assets, net are included in "other deferred charges and assets"; operating lease obligations are included in "other current liabilities" and "other deferred credits and liabilities," as applicable; finance lease ROU assets, net are included in "plant in service"; and finance lease obligations are included in "securities due within one year" and "long-term debt," as applicable.

Lease costs for 2022, 2021, and 2020, which includes both amounts recognized as operations and maintenance expense and amounts capitalized as part of the cost of another asset, are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022						
Lease cost						
Operating lease cost(*)	$ 297	$ 59	$ 198	$ 5	$ 32	$ 15
Finance lease cost:						
Amortization of ROU assets	23	1	15	1	—	—
Interest on lease obligations	13	—	17	1	—	—
Total finance lease cost	36	1	32	2	—	—
Short-term lease costs	64	44	13	—	—	—
Variable lease cost	125	13	105	—	5	—
Sublease income	(1)	—	—	—	—	—
Total lease cost	$ 521	$ 117	$ 348	$ 7	$ 37	$ 15
2021						
Lease cost						
Operating lease cost(*)	$ 313	$ 58	$ 208	$ 2	$ 33	$ 19
Finance lease cost:						
Amortization of ROU assets	21	1	11	1	—	—
Interest on lease obligations	11	—	16	1	—	—
Total finance lease cost	32	1	27	2	—	—
Short-term lease costs	48	15	24	—	—	—
Variable lease cost	96	4	83	—	5	—
Sublease income	1	—	—	—	—	—
Total lease cost	$ 490	$ 78	$ 342	$ 4	$ 38	$ 19
2020						
Lease cost						
Operating lease cost(*)	$ 309	$ 55	$ 212	$ 3	$ 29	$ 19
Finance lease cost:						
Amortization of ROU assets	26	1	15	—	—	—
Interest on lease obligations	11	—	16	—	—	—
Total finance lease cost	37	1	31	—	—	—
Short-term lease costs	39	11	26	—	—	—
Variable lease cost	91	4	76	—	7	—
Sublease income	—	(1)	—	—	—	—
Total lease cost	$ 476	$ 70	$ 345	$ 3	$ 36	$ 19

* Includes operating lease costs related to PPAs at Southern Company, Alabama Power, and Georgia Power totaling $162 million, $48 million, and $180 million, respectively, in 2022, $165 million, $47 million, and $184 million, respectively, in 2021, and $161 million, $43 million, and $184 million, respectively, in 2020.

Georgia Power has variable lease payments that are based on the amount of energy produced by certain renewable generating facilities subject to PPAs, including $45 million, $41 million, and $39 million in 2022, 2021, and 2020, respectively, from finance leases which are included in purchased power on Georgia Power's statements of income, of which $21 million, $20 million, and $20 million was included in purchased power, affiliates in 2022, 2021, and 2020, respectively.

Other information with respect to cash and noncash activities related to leases, as well as weighted-average lease terms and discount rates, is as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022						
Other information						
Cash paid for amounts included in the measurements of lease obligations:						
Operating cash flows from operating leases	$ 303	$ 58	$ 206	$ 5	$ 30	$ 14
Operating cash flows from finance leases	11	—	20	1	—	—
Financing cash flows from finance leases	16	1	10	1	—	—
ROU assets obtained under operating leases	56	10	17	9	—	3
Reassessment of ROU assets under operating leases	16	—	—	—	16	—
ROU assets obtained under finance leases	118	2	116	—	—	—
2021						
Other information						
Cash paid for amounts included in the measurements of lease obligations:						
Operating cash flows from operating leases	$ 308	$ 58	$ 211	$ 2	$ 28	$ 19
Operating cash flows from finance leases	9	—	17	1	—	—
Financing cash flows from finance leases	17	1	9	1	—	—
ROU assets obtained under operating leases	64	3	9	—	72	7

ROU assets obtained under finance leases	3	—	—	—	—	—
2020						
Other information						
Cash paid for amounts included in the measurements of lease obligations:						
Operating cash flows from operating leases	$ 310	$ 55	$ 215	$ 3	$ 28	$ 18
Operating cash flows from finance leases	9	—	18	—	—	—
Financing cash flows from finance leases	22	1	11	—	—	—
ROU assets obtained under operating leases	227	63	32	—	51	4
ROU assets obtained under finance leases	10	2	—	—	—	—

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
At December 31, 2022						
Weighted-average remaining lease term in years:						
Operating leases	17.3	13.0	8.1	4.7	34.0	11.0
Finance leases	17.4	6.4	11.8	12.9	N/A	N/A
Weighted-average discount rate:						
Operating leases	4.51 %	4.87 %	4.52 %	3.49 %	4.86 %	3.79 %
Finance leases	4.87 %	3.00 %	8.06 %	2.74 %	N/A	N/A
At December 31, 2021						
Weighted-average remaining lease term in years:						
Operating leases	15.9	9.1	8.7	6.1	32.8	10.5
Finance leases	18.0	8.7	8.5	13.9	N/A	N/A
Weighted-average discount rate:						
Operating leases	4.41 %	4.37 %	4.45 %	2.74 %	5.20 %	3.61 %
Finance leases	4.82 %	3.09 %	10.81 %	2.74 %	N/A	N/A

Maturities of lease liabilities are as follows:

	At December 31, 2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Maturity Analysis						
Operating leases:						
2023	$ 248	$ 12	$ 191	$ 4	$ 36	$ 11
2024	201	10	165	2	28	11
2025	181	9	138	2	28	11
2026	159	6	135	1	28	8
2027	143	5	135	—	29	3
Thereafter	1,497	64	440	1	1,009	31
Total	2,429	106	1,204	10	1,158	75
Less: Present value discount	844	30	202	1	616	15
Operating lease obligations	$ 1,585	$ 76	$ 1,002	$ 9	$ 542	$ 60
Finance leases:						
2023	$ 33	$ 2	$ 35	$ 2	$ —	$ —
2024	22	1	27	2	—	—
2025	26	1	35	2	—	—
2026	26	1	36	2	—	—
2027	26	—	36	2	—	—
Thereafter	345	—	187	10	—	—
Total	478	5	356	20	—	—
Less: Present value discount	164	—	118	3	—	—
Finance lease obligations	$ 314	$ 5	$ 238	$ 17	$ —	$ —

Payments made under PPAs at Georgia Power for energy generated from certain renewable energy facilities accounted for as operating and finance leases are considered variable lease costs and are therefore not reflected in the above maturity analysis.

Lessor

The Registrants are each considered lessors in various arrangements that have been determined to contain a lease due to the customer's ability to control the use of the underlying asset owned by the applicable Registrant. For the traditional electric operating companies, these arrangements consist of outdoor lighting contracts accounted for as operating leases with initial terms of up to seven years, after which the contracts renew on a month-to-month basis at the customer's option. For Mississippi Power, these arrangements also include a tolling arrangement related to an electric generating unit accounted for as a sales-type lease with a remaining term of 16 years. For Southern Power, these arrangements consist of PPAs related to electric generating units, including solar and wind facilities, accounted for as operating leases with remaining terms of up to 24 years and PPAs related to battery energy storage facilities accounted for as sales-type leases with remaining terms of up to 19 years. Southern Company Gas is the lessor in operating leases related to gas pipelines with remaining terms of up to 20 years. For Southern Company, these arrangements also include PPAs related to fuel cells accounted for as operating leases with remaining terms of up to 11 years.

Lease income for 2022, 2021, and 2020, is as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022						
Lease income - interest income on sales-type leases	$ 25	$ —	$ —	$ 15	$ 10	$ —
Lease income - operating leases	208	77	32	2	85	36
Variable lease income	417	1	—	—	448	—

Total lease income	$ 650	$ 78	$ 32	$ 17	$ 543	$ 36
2021						
Lease income - interest income on sales-type leases	$ 15	$ —	$ —	$ 14	$ 1	$ —
Lease income - operating leases	223	82	42	2	85	35
Variable lease income	429	—	—	—	456	—
Total lease income	$ 667	$ 82	$ 42	$ 16	$ 542	$ 35
2020						
Lease income - interest income on sales-type leases	$ 16	$ —	$ —	$ 12	$ —	$ —
Lease income - operating leases	208	45	58	2	87	35
Variable lease income	419	—	—	—	449	—
Total lease income	$ 643	$ 45	$ 58	$ 14	$ 536	$ 35

Lease payments received under tolling arrangements and PPAs consist of either scheduled payments or variable payments based on the amount of energy produced by the underlying electric generating units. Lease income for Alabama Power and Southern Power is included in wholesale revenues. Scheduled payments to be received under outdoor lighting contracts, tolling arrangements, and PPAs accounted for as leases are presented in the following maturity analyses.

Mississippi Power has a tolling arrangement accounted for as a sales-type lease. During 2020 and 2021, Mississippi Power completed construction of additional leased assets under the lease and, upon completion, the book values of $26 million and $39 million, respectively, were transferred from CWIP to lease receivables. Each transfer represented a non-cash investing transaction for purposes of the statements of cash flows.

During 2021, Southern Power completed construction of a portion of the Garland and Tranquillity battery energy storage facilities' assets and recorded losses totaling $40 million upon commencement of the related PPAs, which Southern Power accounts for as sales-type leases. The losses were due to ITCs retained and expected to be realized by Southern Power and its partners in these projects, and no estimated residual asset value was assumed in calculating the losses. Each lease had an initial term of 20 years. Upon commencement of the leases, the book values of the related assets totaling $210 million were derecognized from CWIP and lease receivables were recorded. The transfers represented noncash investing transactions for purposes of the statement of cash flows. See Note 15 under "Southern Power" for additional information.

The undiscounted cash flows expected to be received for in-service leased assets under the leases are as follows:

	At December 31, 2022		
	Southern Company	Mississippi Power	Southern Power
		(in millions)	
2023	$ 39	$ 24	$ 15
2024	38	23	15
2025	37	22	15
2026	36	21	15
2027	35	20	15
Thereafter	364	164	200
Total undiscounted cash flows	$ 549	$ 274	$ 275
Net investment in sales-type lease(*)	326	157	169
Difference between undiscounted cash flows and discounted cash flows	$ 223	$ 117	$ 106

* For Mississippi Power, included in other current assets and other property and investments on the balance sheets. For Southern Power, included in other current assets ($15 million and $12 million at December 31, 2022 and 2021, respectively) and net investment in sales-type leases ($154 million and $161 million at December 31, 2022 and 2021, respectively) on the balance sheet.

The undiscounted cash flows to be received under operating leases and contracts accounted for as operating leases are as follows:

	At December 31, 2022			
	Southern Company	Alabama Power	Southern Power	Southern Company Gas
		(in millions)		
2023	$ 145	$ 34	$ 88	$ 36
2024	114	6	90	34
2025	105	5	74	29
2026	104	3	73	29
2027	104	3	74	28
Thereafter	796	23	166	382
Total	$ 1,368	$ 74	$ 565	$ 538

Southern Power receives payments for renewable energy under PPAs accounted for as operating leases that are considered contingent rents and are therefore not reflected in the table above. Alabama Power and Southern Power allocate revenue to the nonlease components of PPAs based on the stand-alone selling price of capacity and energy. The undiscounted cash flows to be received under outdoor lighting contracts accounted for as operating leases at Georgia Power and Mississippi Power are immaterial.

Southern Company Leveraged Lease

At December 31, 2020, a subsidiary of Southern Holdings had four leveraged lease agreements related to energy generation, distribution, and transportation assets, including two domestic and two international projects. During 2021, one of the domestic projects was sold and the agreements for both international projects were terminated. At December 31, 2022, the one remaining leveraged lease agreement, which relates to energy generation, had an expected remaining term of nine years. Southern Company continues to receive federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to this investment. Southern Company wrote off the related investment balance in 2020, as discussed below.

During the second quarter 2020, following an evaluation of the recoverability of the lease receivable and the expected residual value of the generation assets at the end of the lease, Southern Company management concluded it was no longer probable that

any of the associated rental payments scheduled after 2032 would be received, because it was no longer probable the generation assets would be successfully remarketed and continue to operate after that date. Revising the estimated cash flows to be received under the leveraged lease to reflect this conclusion resulted in a full impairment of the lease investment and a pre-tax charge to earnings of $154 million ($74 million after tax).

The following table provides a summary of the components of income related to leveraged lease investments. Income was impacted in 2021 and 2020 by the impairment charges discussed below and in Note 15 under "Southern Company." Income in 2021 does not include the impacts of the sale and terminations of leveraged lease projects discussed in Note 15 under "Southern Company."

	2021	2020
	(in millions)	
Pretax leveraged lease income (loss)	$ 17	$ (180)

Pretax leveraged lease income (loss)	$ 17	$ (180)
Income tax benefit (expense)	(5)	98
Net leveraged lease income (loss)	$ 12	$ (82)

On June 30, 2022, the Southern Holdings subsidiary operating the generating plant for the lessee provided notice to the lessee to terminate the related operating and maintenance agreement effective June 30, 2023. The parties to the lease agreement are currently negotiating a potential restructuring, which could result in rescission of the termination notice. The ultimate outcome of this matter cannot be determined at this time but is not expected to have a material impact on Southern Company's financial statements.

The lessee failed to make the semi-annual lease payment due December 15, 2022. As a result, the Southern Holdings subsidiary was unable to make its corresponding payment to the holders of the underlying non-recourse debt related to the generation assets. The parties to the lease have entered into a forbearance agreement which suspends the related contractual rights of the parties while they continue restructuring negotiations. As the remaining amount of Southern Company's lease investment was charged against earnings in the second quarter 2020, termination would not be expected to result in additional charges. Southern Company will continue to monitor the operational performance of the underlying assets and evaluate the ability of the lessee to continue to make the required lease payments and meet its obligations associated with a future closure or retirement of the generation assets and associated properties, including the dry ash landfill.

10. INCOME TAXES

Southern Company files a consolidated federal income tax return and the Registrants file various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis, and each subsidiary is allocated an amount of tax similar to that which would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Federal —						
Current	$ 10	$ 54	$ 38	$ 42	$ (43)	$ 122
Deferred	455	259	152	(16)	56	(3)
	465	313	190	26	13	119
State —						
Current	27	14	(21)	—	2	42
Deferred	303	96	201	11	5	19
	330	110	180	11	7	61
Total	$ 795	$ 423	$ 370	$ 37	$ 20	$ 180

	2021					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Federal —						
Current	$ 50	$ 104	$ 311	$ 25	$ (340)	$ 85
Deferred	36	172	(449)	(15)	343	35
	86	276	(138)	10	3	120
State —						
Current	(25)	23	71	—	(16)	(68)
Deferred	206	73	(101)	11	—	223
	181	96	(30)	11	(16)	155
Total	$ 267	$ 372	$ (168)	$ 21	$ (13)	$ 275

	2020					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Federal —						
Current	$ 199	$ 198	$ 365	$ 18	$ (303)	$ 82
Deferred	70	44	(224)	(14)	299	53
	269	242	141	4	(4)	135
State —						
Current	100	61	60	—	(4)	35
Deferred	24	34	(49)	10	11	3
	124	95	11	10	7	38
Total	$ 393	$ 337	$ 152	$ 14	$ 3	$ 173

Southern Company's and Southern Power's ITCs and PTCs generated in the current tax year and carried forward from prior tax years that cannot be utilized in the current tax year are reclassified from current to deferred taxes in federal income tax expense in

the tables above. Southern Power's ITCs and PTCs reclassified in this manner include $17 million for 2022, $6 million for 2021, and $5 million for 2020. Southern Power received $49 million, $289 million, and $340 million of cash related to federal ITCs under renewable energy initiatives in 2022, 2021, and 2020, respectively. See "Deferred Tax Assets and Liabilities" herein for additional information.

In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies are amortized over the average life of the related property, with such amortization normally applied as a credit to reduce depreciation and amortization in the statements of income. Southern Power's and the natural gas distribution utilities' deferred federal ITCs, as well as certain state ITCs for Nicor Gas, are amortized to income tax expense over the life of the respective asset. ITCs amortized in 2022, 2021, and 2020 were immaterial for the traditional electric operating companies and Southern Company Gas and were as follows for Southern Company and Southern Power:

	Southern Company	Southern Power
	(in millions)	

2022	$ 83	$ 58
2021	84	58
2020	84	59

When Southern Power recognizes tax credits, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation.

State ITCs and other state credits, which are recognized in the period in which the credits are generated, reduced Georgia Power's income tax expense by $53 million in 2022, $66 million in 2021, and $67 million in 2020.

Southern Power's federal and state PTCs, which are recognized in the period in which the credits are generated, reduced Southern Power's income tax expense by $27 million in 2022, $16 million in 2021, and $15 million in 2020.

Effective Tax Rate

Southern Company's effective tax rate is typically lower than the statutory rate due to employee stock plans' dividend deduction, non-taxable AFUDC equity at the traditional electric operating companies, flowback of excess deferred income taxes at the regulated utilities, and federal income tax benefits from ITCs and PTCs primarily at Southern Power.

In July 2021, Southern Company Gas affiliates completed the sale of Sequent. As a result of the sale, changes in state apportionment rates resulted in $85 million of additional net state tax expense. See Note 15 under "Southern Company Gas" for additional information.

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Federal statutory rate	**21.0 %**	**21.0 %**	**21.0 %**	**21.0 %**	**21.0 %**	**21.0 %**
State income tax, net of federal deduction	**6.2**	**4.8**	**6.5**	**4.4**	**1.9**	**6.4**
Employee stock plans' dividend deduction	**(0.5)**	**—**	**—**	**—**	**—**	**—**
Non-deductible book depreciation	**0.6**	**0.5**	**0.6**	**0.3**	**—**	**—**
Flowback of excess deferred income taxes	**(6.6)**	**(1.9)**	**(9.6)**	**(7.8)**	**—**	**(2.5)**
AFUDC-Equity	**(1.1)**	**(0.8)**	**(1.5)**	**—**	**—**	**—**
Federal PTCs	**—**	**—**	**—**	**—**	**(6.6)**	**—**
ITC amortization	**(1.3)**	**(0.1)**	**(0.1)**	**—**	**(17.2)**	**(0.1)**
Noncontrolling interests	**0.5**	**—**	**—**	**—**	**8.4**	**—**
Other	**—**	**0.3**	**—**	**0.3**	**(0.1)**	**(0.9)**
Effective income tax (benefit) rate	**18.8 %**	**23.8 %**	**16.9 %**	**18.2 %**	**7.4 %**	**23.9 %**

	2021					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
State income tax, net of federal deduction	5.5	4.6	(5.7)	4.9	(8.0)	15.1
Employee stock plans' dividend deduction	(0.9)	—	—	—	—	—
Non-deductible book depreciation	0.9	0.5	3.1	0.4	—	—
Flowback of excess deferred income taxes	(11.7)	(2.6)	(49.9)	(15.2)	—	(2.8)
AFUDC-Equity	(1.5)	(0.7)	(6.4)	—	—	—
Federal PTCs	—	—	—	—	(4.6)	—
ITC amortization	(2.2)	(0.1)	(0.4)	—	(29.7)	(0.1)
Noncontrolling interests	0.8	—	—	—	13.4	—
Leveraged lease impairments and dispositions	(1.4)	—	—	—	—	—
Other	(0.1)	0.2	(1.9)	0.6	(0.4)	0.6
Effective income tax (benefit) rate	10.4 %	22.9 %	(40.2) %	11.7 %	(8.3) %	33.8 %

	2020					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
State income tax, net of federal deduction	2.8	5.0	0.5	4.8	2.7	4.0
Employee stock plans' dividend deduction	(0.7)	—	—	—	—	—
Non-deductible book depreciation	0.7	0.6	0.8	0.5	—	—
Flowback of excess deferred income taxes	(8.8)	(3.1)	(12.0)	(18.5)	—	(2.7)
AFUDC-Equity	(0.8)	(0.6)	(1.1)	(0.1)	—	—
Federal PTCs	—	—	—	—	(2.5)	—
ITC amortization	(1.6)	(0.1)	(0.1)	(0.1)	(22.1)	(0.1)
Noncontrolling interests	—	—	—	—	3.1	—
Leveraged lease impairments	(1.6)	—	—	—	—	—
Other	0.2	(0.3)	(0.3)	0.9	(0.9)	0.5
Effective income tax (benefit) rate	11.2 %	22.5 %	8.8 %	8.5 %	1.3 %	22.7 %

Deferred Tax Assets and Liabilities

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements of the Registrants and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	December 31, 2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Deferred tax liabilities —						

Accelerated depreciation	$ 9,443	$ 2,564	$ 3,447	$ 338	$ 1,351	$ 1,505
Property basis differences	2,350	1,303	693	179	—	150
Employee benefit obligations	888	284	412	43	11	68
AROs	876	499	324	—	—	—
Under recovered fuel and natural gas costs	805	185	548	40	—	32
Regulatory assets –						
AROs	2,006	679	1,285	42	—	—
Employee benefit obligations	677	180	226	30	—	15
Remaining book value of retired assets	400	142	253	5	—	—
Premium on reacquired debt	66	9	57	—	—	—
Other	555	179	181	40	14	82
Total deferred income tax liabilities	18,066	6,024	7,426	717	1,376	1,852
Deferred tax assets —						
AROs	2,882	1,178	1,609	42	—	—
ITC and PTC carryforwards	1,685	12	673	—	794	—
Employee benefit obligations	890	198	304	47	9	89
Estimated loss on plants under construction	888	—	888	—	—	—
Other state deferred tax attributes	388	—	12	239	51	7
Federal effect of net state deferred tax liabilities	365	175	88	—	28	92
Other property basis differences	207	—	79	—	109	—
State effect of federal deferred taxes	136	136	—	—	—	—
Other partnership basis differences	111	—	—	—	111	—
Regulatory liability associated with the Tax Reform Legislation (not subject to normalization)	137	127	—	9	—	—
Long-term debt fair value adjustment	85	—	—	—	—	85
Other comprehensive losses	72	4	5	—	5	—
Other	552	213	186	62	17	28
Total deferred income tax assets	8,398	2,043	3,844	399	1,124	301
Valuation allowance	(257)	—	(125)	(41)	(27)	(9)
Net deferred income tax assets	8,141	2,043	3,719	358	1,097	292
Net deferred income taxes (assets)/liabilities	**$ 9,925**	**$ 3,981**	**$ 3,707**	**$ 359**	**$ 279**	**$ 1,560**
Recognized in the balance sheets:						
Accumulated deferred income taxes – assets	**$ (111)**	**$ —**	**$ —**	**$ (107)**	**$ —**	**$ —**
Accumulated deferred income taxes – liabilities	**$ 10,036**	**$ 3,981**	**$ 3,707**	**$ 466**	**$ 279**	**$ 1,560**

	December 31, 2021					
	Southern Company	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**	**Southern Company Gas**
			(in millions)			
Deferred tax liabilities —						
Accelerated depreciation	$ 9,300	$ 2,541	$ 3,340	$ 330	$ 1,421	$ 1,428
Property basis differences	2,301	1,182	781	169	—	148
Federal effect of net state deferred tax assets	—	—	—	22	—	—
Leveraged lease basis differences	61	—	—	—	—	—
Employee benefit obligations	820	268	382	41	11	57
AROs	868	329	494	—	—	—
Under recovered fuel and natural gas costs	315	47	109	15	—	144
Regulatory assets –						
AROs	2,232	863	1,325	44	—	—
Storm damage reserves	18	—	18	—	—	—
Employee benefit obligations	825	205	256	38	—	15
Remaining book value of retired assets	271	145	121	5	—	—
Premium on reacquired debt	72	10	62	—	—	—
Other	368	147	77	34	14	82
Total deferred income tax liabilities	17,451	5,737	6,965	698	1,446	1,874
Deferred tax assets —						
AROs	3,100	1,192	1,819	44	—	—
ITC and PTC carryforwards	1,750	12	704	—	827	—
Employee benefit obligations	1,035	225	342	57	7	77
Estimated loss on plants under construction	825	—	825	—	—	—
Other state deferred tax attributes	361	—	11	246	52	5
Federal effect of net state deferred tax liabilities	305	165	41	—	27	93
Other property basis differences	231	—	90	—	121	—
State effect of federal deferred taxes	135	135	—	—	—	—
Other partnership basis differences	160	—	—	—	160	—
Regulatory liability associated with the Tax Reform Legislation (not subject to normalization)	268	237	19	12	—	—
Long-term debt fair value adjustment	91	—	—	—	—	91
Other comprehensive losses	92	5	15	—	11	—
Other	561	193	153	34	53	62
Total deferred income tax assets	8,914	2,164	4,019	393	1,258	328
Valuation allowance	(207)	—	(73)	(41)	(27)	(9)
Net deferred income tax assets	8,707	2,164	3,946	352	1,231	319
Net deferred income taxes (assets)/liabilities	**$ 8,744**	**$ 3,573**	**$ 3,019**	**$ 346**	**$ 215**	**$ 1,555**
Recognized in the balance sheets:						
Accumulated deferred income taxes – assets	**$ (118)**	**$ —**	**$ —**	**$ (118)**	**$ —**	**$ —**
Accumulated deferred income taxes – liabilities	**$ 8,862**	**$ 3,573**	**$ 3,019**	**$ 464**	**$ 215**	**$ 1,555**

The traditional electric operating companies and the natural gas distribution utilities have tax-related regulatory assets (deferred income tax charges) and regulatory liabilities (deferred income tax credits). The regulatory assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law,

and taxes applicable to capitalized interest. The regulatory liabilities are primarily attributable to deferred taxes

previously recognized at rates higher than the current enacted tax law and to unamortized ITCs. See Note 2 for each Registrant's related balances at December 31, 2022 and 2021.

Tax Credit Carryforwards

Federal ITC/PTC carryforwards at December 31, 2022 were as follows:

	Southern Company	Alabama Power	Georgia Power	Southern Power
		(in millions)		
Federal ITC/PTC carryforwards	$ 1,148	$ 12	$ 135	$ 794
Tax year in which federal ITC/PTC carryforwards begin expiring	2031	2032	2031	2035
Year by which federal ITC/PTC carryforwards are expected to be utilized	2026	2025	2025	2026

The estimated tax credit utilization reflects the various sale transactions described in Note 15 and could be further delayed by numerous factors, including the acquisition of additional renewable projects, the purchase of rights to additional PTCs of Plant Vogtle Units 3 and 4 pursuant to certain joint ownership agreements, an increase in Georgia Power's ownership interest percentage in Plant Vogtle Units 3 and 4, changes in taxable income projections, and potential income tax rate changes. See Note 2 under "Georgia Power – Nuclear Construction" for additional information on Plant Vogtle Units 3 and 4.

At December 31, 2022, Georgia Power also had approximately $434 million in net state investment and other net state tax credit carryforwards for the State of Georgia that will expire between tax years 2022 and 2031 and are not expected to be fully utilized. Georgia Power has a net state valuation allowance of $98 million associated with these carryforwards.

The ultimate outcome of these matters cannot be determined at this time.

Net Operating Loss Carryforwards

At December 31, 2022, the net state income tax benefit of state and local NOL carryforwards for Southern Company's subsidiaries were as follows:

Company/Jurisdiction	Approximate Net State Income Tax Benefit of NOL Carryforwards	Tax Year NOL Begins Expiring
	(in millions)	
Mississippi Power		
Mississippi	$ 189	2031
Southern Power		
Oklahoma	27	2035
Florida	10	2034
Other states	3	Various
Southern Power Total	$ 40	
Other(*)		
Georgia	23	2042
New York	11	2036
New York City	14	2036
Other states	21	Various
Southern Company Total	$ 298	

* Represents other non-registrant Southern Company subsidiaries. Alabama Power, Georgia Power, and Southern Company Gas did not have material state or local NOL carryforwards at December 31, 2022.

State NOLs for Mississippi, Oklahoma, and Florida are not expected to be fully utilized prior to expiration. At December 31, 2022, Mississippi Power had a net state valuation allowance of $32 million for the Mississippi NOL, Southern Power had net state valuation allowances of $11 million for the Oklahoma NOL and $10 million for the Florida NOL, and Southern Company had a net valuation allowance of $25 million for the New York and New York City NOLs.

The ultimate outcome of these matters cannot be determined at this time.

Unrecognized Tax Benefits

Changes in unrecognized tax benefits for the periods presented were as follows:

	Southern Company	Southern Company Gas
	(in millions)	
Unrecognized tax benefits at December 31, 2019	$ —	$ —
Tax positions changes – increase from prior periods	44	—
Unrecognized tax benefits at December 31, 2020	$ 44	$ —
Tax positions changes – increase from prior periods	3	—
Unrecognized tax benefits at December 31, 2021	$ 47	$ —
Tax positions changes – increase from prior periods	33	32
Unrecognized tax benefits at December 31, 2022	$ 80	$ 32

The unrecognized tax positions increase from prior periods for 2020 primarily relates to a 2019 state tax filing position to exclude certain gains from 2019 dispositions from taxation in a certain unitary state. It is possible that this position will be resolved in the next 12 months, and if accepted by the state, this position would decrease Southern Company's annual effective tax rate.

The unrecognized tax positions increase from prior periods for 2022 is primarily related to the amendment of certain 2018 state tax filing positions related to Southern Company Gas dispositions. If accepted by the states, these positions would decrease Southern Company's and Southern Company Gas' annual effective tax rates. The ultimate outcome of these unrecognized tax benefits is dependent on acceptance by each state and is not expected to be resolved within the next 12 months.

All of the Registrants classify interest on tax uncertainties as interest expense. Accrued interest for all tax positions was immaterial for all years presented. None of the Registrants accrued any penalties on uncertain tax positions.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2021. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Registrants' state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2015.

11. RETIREMENT BENEFITS

The Southern Company system has a qualified defined benefit, trusteed pension plan covering substantially all employees, with the exception of PowerSecure employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2022 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2023. The Southern Company system also provides certain non-qualified defined benefits for a select group of management and highly compensated employees, which are funded on a cash basis. In addition, the Southern Company system provides certain medical

care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional electric operating companies fund other postretirement trusts to the extent required by their respective regulatory commissions. Southern Company Gas has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses. For the year ending December 31, 2023, no contributions to any other postretirement trusts are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

	2022					
Assumptions used to determine net periodic costs:	**Southern Company**	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**	**Southern Company Gas**
Pension plans						
Discount rate – benefit obligations	**3.09%**	**3.12%**	**3.07%**	**3.07%**	**3.21%**	**3.04%**
Discount rate – interest costs	**2.55**	**2.58**	**2.51**	**2.54**	**2.79**	**2.53**
Discount rate – service costs	**3.34**	**3.36**	**3.37**	**3.35**	**3.36**	**3.21**
Expected long-term return on plan assets	**8.25**	**8.25**	**8.25**	**8.25**	**8.25**	**8.25**
Annual salary increase	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**
Other postretirement benefit plans						
Discount rate – benefit obligations	**2.90%**	**2.95%**	**2.87%**	**2.88%**	**3.07%**	**2.82%**
Discount rate – interest costs	**2.32**	**2.38**	**2.30**	**2.27**	**2.55**	**2.17**
Discount rate – service costs	**3.26**	**3.30**	**3.27**	**3.26**	**3.25**	**3.22**
Expected long-term return on plan assets	**7.21**	**7.54**	**6.88**	**7.22**	**—**	**6.08**
Annual salary increase	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**

	2021					
Assumptions used to determine net periodic costs:	**Southern Company**	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**	**Southern Company Gas**
Pension plans						
Discount rate – benefit obligations	2.81%	2.85%	2.79%	2.80%	2.99%	2.75%
Discount rate – interest costs	2.13	2.17	2.09	2.12	2.46	2.10
Discount rate – service costs	3.18	3.23	3.21	3.20	3.22	2.97
Expected long-term return on plan assets	8.25	8.25	8.25	8.25	8.25	8.25
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80
Other postretirement benefit plans						
Discount rate – benefit obligations	2.56%	2.63%	2.52%	2.53%	2.78%	2.46%
Discount rate – interest costs	1.84	1.91	1.82	1.78	2.12	1.64
Discount rate – service costs	3.07	3.13	3.08	3.06	3.05	3.01
Expected long-term return on plan assets	7.09	7.18	6.84	6.98	—	6.54
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80

	2020					
Assumptions used to determine net periodic costs:	**Southern Company**	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**	**Southern Company Gas**
Pension plans						
Discount rate – benefit obligations	3.41%	3.44%	3.40%	3.41%	3.52%	3.39%
Discount rate – interest costs	2.99	3.01	2.96	2.99	3.18	2.99
Discount rate – service costs	3.66	3.69	3.67	3.67	3.70	3.53
Expected long-term return on plan assets	8.25	8.25	8.25	8.25	8.25	8.25
Annual salary increase	4.73	4.73	4.73	4.73	4.73	4.73
Other postretirement benefit plans						
Discount rate – benefit obligations	3.24%	3.28%	3.22%	3.22%	3.39%	3.19%
Discount rate – interest costs	2.80	2.84	2.79	2.76	2.97	2.71
Discount rate – service costs	3.57	3.61	3.57	3.57	3.57	3.52
Expected long-term return on plan assets	7.25	7.36	7.05	7.07	—	6.69
Annual salary increase	4.73	4.73	4.73	4.73	4.73	4.73

	2022					
Assumptions used to determine benefit obligations:	**Southern Company**	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**	**Southern Company Gas**
Pension plans						
Discount rate	**5.25%**	**5.26%**	**5.25%**	**5.25%**	**5.31%**	**5.24%**
Annual salary increase	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**
Other postretirement benefit plans						
Discount rate	**5.18%**	**5.20%**	**5.17%**	**5.17%**	**5.24%**	**5.16%**
Annual salary increase	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**

	2021					
Assumptions used to determine benefit obligations:	**Southern Company**	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**	**Southern Company Gas**
Pension plans						
Discount rate	3.09%	3.12%	3.07%	3.07%	3.21%	3.04%
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80
Other postretirement benefit plans						

Other postretirement benefit plans						
Discount rate	2.90%	2.95%	2.87%	2.88%	3.07%	2.82%
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80

The Registrants estimate the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of the different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio. The Registrants set the expected rate of return assumption using an arithmetic mean which represents the expected simple average return to be earned by the pension plan assets over any one year. The Registrants believe the use of the arithmetic mean is more compatible with the expected rate of return's function of estimating a single year's investment return.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO for the Registrants at December 31, 2022 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.60%	4.50%	2030
Post-65 medical	5.50	4.50	2030
Post-65 prescription	7.50	4.50	2031

Pension Plans

The total accumulated benefit obligation for the pension plans at December 31, 2022 and 2021 was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2022	$ 11,422	$ 2,601	$ 3,534	$ 520	$ 135	$ 801
December 31, 2021	14,687	3,362	4,562	672	178	1,030

Actuarial gains of $3.9 billion and $393 million were recorded for the annual remeasurement of the Southern Company system pension plans at December 31, 2022 and 2021, respectively, primarily due to increases of 216 basis points and 28 basis points, respectively, in the overall discount rate used to calculate the benefit obligation as a result of higher market interest rates.

Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2022 and 2021 were as follows:

	2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	**$ 16,382**	**$ 3,806**	**$ 5,012**	**$ 743**	**$ 222**	**$ 1,134**
Service cost	**412**	**99**	**103**	**17**	**9**	**34**
Interest cost	**408**	**96**	**123**	**18**	**6**	**28**
Benefits paid	**(692)**	**(144)**	**(226)**	**(30)**	**(5)**	**(75)**
Actuarial gain	**(3,908)**	**(951)**	**(1,161)**	**(179)**	**(69)**	**(253)**
Balance at end of year	**12,602**	**2,906**	**3,851**	**569**	**163**	**868**
Change in plan assets						
Fair value of plan assets at beginning of year	**17,225**	**4,141**	**5,415**	**786**	**213**	**1,241**
Actual loss on plan assets	**(2,376)**	**(579)**	**(753)**	**(110)**	**(31)**	**(167)**
Employer contributions	**61**	**9**	**20**	**3**	**1**	**3**
Benefits paid	**(692)**	**(144)**	**(226)**	**(30)**	**(5)**	**(75)**
Fair value of plan assets at end of year	**14,218**	**3,427**	**4,456**	**649**	**178**	**1,002**
Accrued asset	**$ 1,616**	**$ 521**	**$ 605**	**$ 80**	**$ 15**	**$ 134**

	2021					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	$ 16,646	$ 3,854	$ 5,127	$ 754	$ 217	$ 1,189
Service cost	434	102	112	18	10	37
Interest cost	346	82	104	16	5	24
Benefits paid	(651)	(137)	(210)	(28)	(4)	(73)
Actuarial gain	(393)	(95)	(121)	(17)	(6)	(43)
Balance at end of year	16,382	3,806	5,012	743	222	1,134
Change in plan assets						
Fair value of plan assets at beginning of year	15,367	3,684	4,844	701	186	1,123
Actual return on plan assets	2,449	586	781	111	30	181
Employer contributions	60	8	—	2	1	10
Benefits paid	(651)	(137)	(210)	(28)	(4)	(73)
Fair value of plan assets at end of year	17,225	4,141	5,415	786	213	1,241
Accrued asset (liability)	$ 843	$ 335	$ 403	$ 43	$ (9)	$ 107

The projected benefit obligations for the qualified and non-qualified pension plans at December 31, 2022 are shown in the following table. All pension plan assets are related to the qualified pension plan.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Projected benefit obligations:						

Qualified pension plan	$ 11,928	$ 2,799	$ 3,717	$ 540	$ 140	$ 819
Non-qualified pension plan	674	107	134	28	23	49

Amounts recognized in the balance sheets at December 31, 2022 and 2021 related to the Registrants' pension plans consist of the following:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2022:						
Prepaid pension costs[a]	**$ 2,290**	**$ 629**	**$ 738**	**$ 108**	**$ 37**	**$ 183**
Other regulatory assets, deferred[b]	**2,455**	**679**	**887**	**123**	**—**	**111**
Other current liabilities	**(56)**	**(10)**	**(12)**	**(2)**	**(2)**	**(3)**
Employee benefit obligations[c]	**(618)**	**(98)**	**(121)**	**(26)**	**(20)**	**(42)**
Other regulatory liabilities, deferred	**(85)**	—	—	—	—	—
AOCI	**24**	**—**	**—**	**—**	**11**	**(75)**
December 31, 2021:						
Prepaid pension costs[a]	$ 1,657	$ 464	$ 563	$ 78	$ 20	$ 175
Other regulatory assets, deferred[b]	2,920	809	971	146	—	91
Other current liabilities	(55)	(9)	(12)	(2)	(2)	(2)
Employee benefit obligations[c]	(759)	(120)	(148)	(33)	(27)	(66)
Other regulatory liabilities, deferred	(119)	—	—	—	—	—
AOCI	100	—	—	—	35	(45)

(a) Included in prepaid pension and other postretirement benefit costs on Alabama Power's balance sheet and other deferred charges and assets on Southern Power's consolidated balance sheet.

(b) Amounts for Southern Company exclude regulatory assets of $190 million and $210 million at December 31, 2022 and 2021, respectively, associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company.

(c) Included in other deferred credits and liabilities on Southern Power's consolidated balance sheets.

Presented below are the amounts included in regulatory assets at December 31, 2022 and 2021 related to the portion of the defined benefit pension plan attributable to Southern Company, the traditional electric operating companies, and Southern Company Gas that had not yet been recognized in net periodic pension cost.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Balance at December 31, 2022					
Regulatory assets:					
Prior service cost	**$ 10**	**$ 4**	**$ 7**	**$ 1**	**$ (9)**
Net loss	**2,361**	**675**	**880**	**122**	**66**
Regulatory amortization	**—**	**—**	**—**	**—**	**54**
Total regulatory assets[*]	**$ 2,371**	**$ 679**	**$ 887**	**$ 123**	**$ 111**
Balance at December 31, 2021					
Regulatory assets:					
Prior service cost	$ 11	$ 5	$ 8	$ 1	$ (11)
Net loss	2,790	804	963	145	38
Regulatory amortization	—	—	—	—	64
Total regulatory assets[*]	$ 2,801	$ 809	$ 971	$ 146	$ 91

* Amounts for Southern Company exclude regulatory assets of $190 million and $210 million at December 31, 2022 and 2021, respectively, associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company.

The changes in the balance of regulatory assets related to the portion of the defined benefit pension plan attributable to Southern Company, the traditional electric operating companies, and Southern Company Gas for the years ended December 31, 2022 and 2021 are presented in the following table:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Regulatory assets (liabilities):[*]					
Balance at December 31, 2020	$ 4,621	$ 1,286	$ 1,598	$ 235	$ 205
Net gain	(1,523)	(394)	(527)	(74)	(97)
Reclassification adjustments:					
Amortization of prior service costs	(1)	(1)	(1)	—	2
Amortization of net loss	(296)	(82)	(99)	(15)	(9)
Amortization of regulatory assets[*]	—	—	—	—	(10)
Total reclassification adjustments	(297)	(83)	(100)	(15)	(17)
Total change	(1,820)	(477)	(627)	(89)	(114)
Balance at December 31, 2021	$ 2,801	$ 809	$ 971	$ 146	$ 91
Net (gain) loss	**(183)**	**(67)**	**(9)**	**(12)**	**27**
Reclassification adjustments:					
Amortization of prior service costs	**(1)**	**(1)**	**(1)**	**—**	**2**
Amortization of net gain (loss)	**(246)**	**(62)**	**(74)**	**(11)**	**1**
Amortization of regulatory assets[*]	**—**	**—**	**—**	**—**	**(10)**
Total reclassification adjustments	**(247)**	**(63)**	**(75)**	**(11)**	**(7)**
Total change	**(430)**	**(130)**	**(84)**	**(23)**	**20**
Balance at December 31, 2022	**$ 2,371**	**$ 679**	**$ 887**	**$ 123**	**$ 111**

* Amounts for Southern Company exclude regulatory assets of $190 million and $210 million at December 31, 2022 and 2021, respectively, associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company.

Presented below are the amounts included in AOCI at December 31, 2022 and 2021 related to the portion of the defined benefit pension plan attributable to Southern Company, Southern Power, and

Southern Company Gas that had not yet been recognized in net periodic pension cost.

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
Balance at December 31, 2022			
AOCI:			
Prior service cost	**$ (2)**	**$ —**	**$ (3)**
Net (gain) loss	**26**	**11**	**(72)**
Total AOCI	**$ 24**	**$ 11**	**$ (75)**
Balance at December 31, 2021			
AOCI:			
Prior service cost	$ (2)	$ —	$ (3)
Net (gain) loss	102	35	(42)
Total AOCI	$ 100	$ 35	$ (45)

The components of OCI related to the portion of the defined benefit pension plan attributable to Southern Company, Southern Power, and Southern Company Gas for the years ended December 31, 2022 and 2021 are presented in the following table:

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
AOCI:			
Balance at December 31, 2020	$ 245	$ 60	$ 1
Net gain	(128)	(22)	(47)
Reclassification adjustments:			
Amortization of net gain (loss)	(17)	(3)	1
Total change	(145)	(25)	(46)
Balance at December 31, 2021	$ 100	$ 35	$ (45)
Net gain	**(82)**	**(22)**	**(30)**
Reclassification adjustments:			
Amortization of net gain (loss)	**6**	**(2)**	—
Total reclassification adjustments	**6**	**(2)**	—
Total change	**(76)**	**(24)**	**(30)**
Balance at December 31, 2022	**$ 24**	**$ 11**	**$ (75)**

Components of net periodic pension cost for the Registrants were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022						
Service cost	**$ 412**	**$ 99**	**$ 103**	**$ 17**	**$ 9**	**$ 34**
Interest cost	**408**	**96**	**123**	**18**	**6**	**28**
Expected return on plan assets	**(1,265)**	**(306)**	**(399)**	**(57)**	**(15)**	**(91)**
Recognized net loss	**240**	**62**	**75**	**11**	**2**	**8**
Net amortization	**—**	**1**	**1**	**—**	**—**	**15**
Prior service cost	—	—	—	—	—	**(3)**
Net periodic pension cost (income)	**$ (205)**	**$ (48)**	**$ (97)**	**$ (11)**	**$ 2**	**$ (9)**
2021						
Service cost	$ 434	$ 102	$ 112	$ 18	$ 10	$ 37
Interest cost	346	82	104	16	5	24
Expected return on plan assets	(1,191)	(287)	(375)	(55)	(14)	(86)
Recognized net loss	314	82	100	15	3	13
Net amortization	1	1	1	—	—	15
Prior service cost	—	—	—	—	—	(3)
Net periodic pension cost (income)	$ (96)	$ (20)	$ (58)	$ (6)	$ 4	$ —
2020						
Service cost	$ 376	$ 89	$ 96	$ 15	$ 8	$ 33
Interest cost	432	100	133	20	6	31
Expected return on plan assets	(1,100)	(264)	(347)	(51)	(13)	(75)
Recognized net loss	269	71	86	13	2	6
Net amortization	1	1	1	—	—	15
Prior service cost	—	—	—	—	—	(3)
Net periodic pension cost (income)	$ (22)	$ (3)	$ (31)	$ (3)	$ 3	$ 7

The service cost component of net periodic pension cost is included in operations and maintenance expenses and all other components of net periodic pension cost are included in other income (expense), net in the Registrants' statements of income.

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Registrants have elected to amortize changes in the market value of return-seeking plan assets over five years and to recognize the changes in the market value of liability-hedging plan assets immediately. Given the significant concentration in return-seeking plan assets, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2022, estimated benefit payments were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Benefit Payments:						
2023	$ 734	$ 155	$ 230	$ 32	$ 6	$ 83
2024	735	160	236	33	7	57
2025	760	167	243	34	7	58
2026	784	173	248	35	7	60
2027	806	178	252	36	8	61
2028 to 2032	4,262	952	1,304	192	43	323

Other Postretirement Benefits

Changes in the APBO and the fair value of the Registrants' plan assets during the plan years ended December 31, 2022 and 2021 were as follows:

	2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	**$ 1,849**	**$ 440**	**$ 656**	**$ 76**	**$ 11**	**$ 237**
Service cost	**23**	**6**	**6**	**1**	**—**	**1**
Interest cost	**42**	**10**	**15**	**2**	**—**	**5**
Benefits paid	**(109)**	**(23)**	**(38)**	**(4)**	**(1)**	**(18)**
Actuarial gain	**(365)**	**(89)**	**(125)**	**(16)**	**(1)**	**(46)**
Retiree drug subsidy	**1**	**—**	**—**	**—**	**—**	**—**
Balance at end of year	**1,441**	**344**	**514**	**59**	**9**	**179**
Change in plan assets						
Fair value of plan assets at beginning of year	**1,251**	**489**	**450**	**29**	**—**	**143**
Actual loss on plan assets	**(218)**	**(98)**	**(71)**	**(4)**	**—**	**(25)**
Employer contributions	**73**	**4**	**27**	**3**	**1**	**13**
Benefits paid	**(108)**	**(23)**	**(38)**	**(4)**	**(1)**	**(18)**
Fair value of plan assets at end of year	**998**	**372**	**368**	**24**	**—**	**113**
Accrued asset (liability)	**$ (443)**	**$ 28**	**$ (146)**	**$ (35)**	**$ (9)**	**$ (66)**

	2021					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	$ 1,948	$ 463	$ 699	$ 81	$ 12	$ 248
Service cost	24	6	7	1	—	2
Interest cost	35	9	12	1	—	4
Benefits paid	(105)	(22)	(36)	(5)	—	(18)
Actuarial (gain) loss	(54)	(16)	(26)	(2)	(1)	1
Retiree drug subsidy	1	—	—	—	—	—
Balance at end of year	1,849	440	656	76	11	237
Change in plan assets						
Fair value of plan assets at beginning of year	1,158	458	427	27	—	128
Actual return on plan assets	154	55	55	4	—	18
Employer contributions	43	(2)	4	3	—	15
Benefits paid	(104)	(22)	(36)	(5)	—	(18)
Fair value of plan assets at end of year	1,251	489	450	29	—	143
Accrued asset (liability)	$ (598)	$ 49	$ (206)	$ (47)	$ (11)	$ (94)

Amounts recognized in the balance sheets at December 31, 2022 and 2021 related to the Registrants' other postretirement benefit plans consist of the following:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2022:						
Prepaid other postretirement benefit costs[a]	**$ —**	**$ 28**	**$ —**	**$ —**	**$ —**	**$ —**
Other regulatory assets, deferred[b]	**34**	**—**	**19**	**—**	**—**	**—**
Other current liabilities	**(6)**	**—**	**—**	**—**	**(1)**	**—**
Employee benefit obligations[c]	**(437)**	**—**	**(146)**	**(35)**	**(8)**	**(66)**
Other regulatory liabilities, deferred	**(170)**	**(21)**	**(58)**	**(9)**	**—**	**(58)**
AOCI	**(4)**	**—**	**—**	**—**	**—**	**(2)**
December 31, 2021:						
Prepaid other postretirement benefit costs[a]	$ —	$ 49	$ —	$ —	$ —	$ —
Other regulatory assets, deferred[b]	97	—	30	2	—	—
Other current liabilities	(5)	—	—	—	—	—
Employee benefit obligations[c]	(593)	—	(206)	(47)	(11)	(94)
Other regulatory liabilities, deferred	(171)	(62)	(40)	(1)	—	(34)
AOCI	—	—	—	—	2	(5)

(a) Included in prepaid pension and other postretirement benefit costs on Alabama Power's balance sheet.

(b) Amounts for Southern Company exclude regulatory assets of $32 million and $40 million at December 31, 2022 and 2021, respectively, associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company.

(c) Included in other deferred credits and liabilities on Southern Power's consolidated balance sheets.

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2022 and 2021 related to the other postretirement benefit plans of Southern Company, the traditional electric operating companies, and Southern Company Gas that had not yet been recognized in net periodic other postretirement benefit cost.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Balance at December 31, 2022:					
Regulatory assets (liabilities):					
Prior service cost	**$ 14**	**$ 4**	**$ 6**	**$ 1**	**$ 1**
Net gain	**(150)**	**(25)**	**(45)**	**(10)**	**(64)**
Regulatory amortization	**—**	**—**	**—**	**—**	**5**
Total regulatory assets (liabilities)(*)	**$ (136)**	**$ (21)**	**$ (39)**	**$ (9)**	**$ (58)**
Balance at December 31, 2021:					
Regulatory assets (liabilities):					
Prior service cost	$ 13	$ 3	$ 5	$ 1	$ 1
Net gain	(87)	(65)	(15)	—	(51)
Regulatory amortization	—	—	—	—	16
Total regulatory assets (liabilities)(*)	$ (74)	$ (62)	$ (10)	$ 1	$ (34)

* Amounts for Southern Company exclude regulatory assets of $32 million and $40 million at December 31, 2022 and 2021, respectively, associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company.

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2022 and 2021 are presented in the following table:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Net regulatory assets (liabilities):(*)					
Balance at December 31, 2020	$ 51	$ (21)	$ 47	$ 5	$ (23)
Net gain	(120)	(41)	(55)	(4)	(2)
Reclassification adjustments:					
Amortization of prior service costs	1	—	1	—	—
Amortization of net loss	(6)	—	(3)	—	—
Amortization of regulatory assets(*)	—	—	—	—	(9)
Total reclassification adjustments	(5)	—	(2)	—	(9)
Total change	(125)	(41)	(57)	(4)	(11)
Balance at December 31, 2021	$ (74)	$ (62)	$ (10)	$ 1	$ (34)
Net (gain) loss	(64)	41	(27)	(10)	(13)
Reclassification adjustments:					
Amortization of prior service costs	1	—	—	—	—
Amortization of net gain (loss)	1	—	(2)	—	—
Amortization of regulatory assets(*)	—	—	—	—	(11)
Total reclassification adjustments	2	—	(2)	—	(11)
Total change	(62)	41	(29)	(10)	(24)
Balance at December 31, 2022	$ (136)	$ (21)	$ (39)	$ (9)	$ (58)

* Amounts for Southern Company exclude regulatory assets of $32 million and $40 million at December 31, 2022 and 2021, respectively, associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company.

Presented below are the amounts included in AOCI at December 31, 2022 and 2021 related to the other postretirement benefit plans of Southern Company, Southern Power, and Southern Company Gas that had not yet been recognized in net periodic other postretirement benefit cost.

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
Balance at December 31, 2022			
AOCI:			
Prior service cost	**$ 1**	**$ —**	**$ —**
Net (gain) loss	**(5)**	**—**	**(2)**
Total AOCI	**$ (4)**	**$ —**	**$ (2)**
Balance at December 31, 2021			
AOCI:			
Prior service cost	$ 1	$ —	$ 1
Net (gain) loss	(1)	2	(6)
Total AOCI	$ —	$ 2	$ (5)

The components of OCI related to the other postretirement benefit plans for the plan years ended December 31, 2022 and 2021 are presented in the following table:

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
AOCI:			
Balance at December 31, 2020	$ 8	$ 3	$ —
Net gain	(11)	(1)	

Net gain			(11)	(1)		—
Reclassification adjustments:						
Amortization of net gain (loss)			3	—		(5)
Total change			(8)	(1)		(5)
Balance at December 31, 2021			$ —	$ 2		$ (5)
Net gain			(3)	(2)		—
Reclassification adjustments:						
Amortization of net gain (loss)			(1)	—		3
Total change			(4)	(2)		3
Balance at December 31, 2022			$ (4)	$ —		$ (2)

Components of the other postretirement benefit plans' net periodic cost for the Registrants were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022						
Service cost	**$ 23**	**$ 6**	**$ 6**	**$ 1**	**$ —**	**$ 1**
Interest cost	**42**	**10**	**15**	**2**	**—**	**5**
Expected return on plan assets	**(80)**	**(32)**	**(28)**	**(2)**	**1**	**(9)**
Net amortization	**(1)**	**—**	**2**	**—**	**—**	**6**
Net periodic postretirement benefit cost (income)	**$ (16)**	**$ (16)**	**$ (5)**	**$ 1**	**$ 1**	**$ 3**
2021						
Service cost	$ 24	$ 6	$ 7	$ 1	$ —	$ 2
Interest cost	35	9	12	1	—	4
Expected return on plan assets	(76)	(30)	(26)	(1)	1	(10)
Net amortization	2	—	2	—	—	6
Net periodic postretirement benefit cost (income)	$ (15)	$ (15)	$ (5)	$ 1	$ 1	$ 2
2020						
Service cost	$ 22	$ 6	$ 6	$ 1	$ 1	$ 2
Interest cost	54	13	20	2	—	7
Expected return on plan assets	(72)	(29)	(26)	(1)	—	(10)
Net amortization	1	—	2	—	—	6
Net periodic postretirement benefit cost (income)	$ 5	$ (10)	$ 2	$ 2	$ 1	$ 5

The service cost component of net periodic postretirement benefit cost is included in operations and maintenance expenses and all other components of net periodic postretirement benefit cost are included in other income (expense), net in the Registrants' statements of income.

The Registrants' future benefit payments, including prescription drug benefits, are provided in the table below. These amounts reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Benefit payments:						
2023	$ 115	$ 25	$ 41	$ 5	$ 1	$ 18
2024	110	24	39	5	1	17
2025	114	26	41	5	1	17
2026	113	26	41	5	1	16
2027	113	26	41	5	1	16
2028 to 2032	551	130	199	22	1	68

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Registrants' investment policies for both the pension plans and the other postretirement benefit plans cover a diversified mix of assets as described below. Derivative instruments may be used to gain efficient exposure to the various asset classes and as hedging tools. Additionally, the Registrants minimize the risk of large losses primarily through diversification but also monitor and manage other aspects of risk.

The investment strategy for plan assets related to the Southern Company system's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Southern Company system employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Southern Company's investment strategy also includes adjusting the established asset allocation to invest a larger portion of the portfolio in fixed rate debt securities should the qualified pension plan achieve a predetermined funding threshold, which occurred during 2022.

Investment Strategies and Benefit Plan Asset Fair Values

A description of the major asset classes that the pension and other postretirement benefit plans are comprised of, along with the valuation methods used for fair value measurement, is provided below:

Description	Valuation Methodology
Domestic equity: A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches. **International equity:** A mix of large and small capitalization growth and value stocks with developed and emerging markets exposure, managed both actively and through fundamental indexing approaches.	Domestic and international equities such as common stocks, American depositary receipts, and real estate investment trusts that trade on public exchanges are classified as Level 1 investments and are valued at the closing price in the active market. Equity funds with unpublished prices that are comprised of publicly traded securities (such as commingled/pooled funds) are also valued at the closing price in the active market, but are classified as Level 2.
	Investments in fixed income securities, including fixed income pooled funds, are generally

Fixed income: A mix of domestic and international bonds.	investments in fixed income securities, including fixed income pooled funds, are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
Trust-owned life insurance (TOLI): Investments of taxable trusts aimed at minimizing the impact of taxes on the portfolio.	Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate accounts. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
Real estate: Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities. **Special situations:** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies, as well as investments in promising new strategies of a longer-term nature. **Private equity:** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.	Investments in real estate, special situations, and private equity are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate. The fair values presented herein exclude cash, receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

The fair values, and actual allocations relative to the target allocations, of the Southern Company system's pension plans at December 31, 2022 and 2021 are presented below.

	Fair Value Measurements Using						
At December 31, 2022:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**	**Target Allocation**	**Actual Allocation**
			(in millions)				
Southern Company							
Assets:							
Equity:						45 %	43 %
Domestic equity	$ 2,078	$ 691	$ —	$ —	$ 2,769		
International equity	2,166	1,090	—	—	3,256		
Fixed income:						30	28
U.S. Treasury, government, and agency bonds	—	1,469	—	—	1,469		
Mortgage- and asset-backed securities	—	29	—	—	29		
Corporate bonds	—	1,494	—	—	1,494		
Pooled funds	—	607	—	—	607		
Cash equivalents and other	399	7	—	—	406		
Real estate investments	376	—	—	1,887	2,263	13	15
Special situations	—	—	—	187	187	3	2
Private equity	—	—	—	1,717	1,717	9	12
Total	$ 5,019	$ 5,387	$ —	$ 3,791	$ 14,197	100 %	100 %
Liabilities:							
Derivatives	(4)	—	—	—	(4)		
Total	$ 5,015	$ 5,387	$ —	$ 3,791	$ 14,193	100 %	100 %
Alabama Power							
Assets:							
Equity:						45 %	43 %
Domestic equity	$ 500	$ 167	$ —	$ —	$ 667		
International equity	522	263	—	—	785		
Fixed income:						30	28
U.S. Treasury, government, and agency bonds	—	354	—	—	354		
Mortgage- and asset-backed securities	—	7	—	—	7		
Corporate bonds	—	360	—	—	360		
Pooled funds	—	146	—	—	146		
Cash equivalents and other	96	2	—	—	98		
Real estate investments	91	—	—	455	546	13	15
Special situations	—	—	—	45	45	3	2
Private equity	—	—	—	414	414	9	12
Total	$ 1,209	$ 1,299	$ —	$ 914	$ 3,422	100 %	100 %
Liabilities:							
Derivatives	(1)	—	—	—	(1)		
Total	$ 1,208	$ 1,299	$ —	$ 914	$ 3,421	100 %	100 %
Georgia Power							
Assets:							
Equity:						45 %	43 %
Domestic equity	$ 651	$ 217	$ —	$ —	$ 868		
International equity	678	342	—	—	1,020		
Fixed income:						30	28
U.S. Treasury, government, and agency bonds	—	460	—	—	460		
Mortgage- and asset-backed securities	—	9	—	—	9		
Corporate bonds	—	468	—	—	468		
Pooled funds	—	190	—	—	190		

Cash equivalents and other	125	2	—	—	127		
Real estate investments	118	—	—	591	709	13	15
Special situations	—	—	—	59	59	3	2
Private equity	—	—	—	538	538	9	12
Total	$ 1,572	$ 1,688	$ —	$ 1,188	$ 4,448	100 %	100 %
Liabilities:							
Derivatives	(1)	—	—	—	(1)		
Total	$ 1,571	$ 1,688	$ —	$ 1,188	$ 4,447	100 %	100 %
Mississippi Power							
Assets:							
Equity:						45 %	43 %
Domestic equity	$ 95	$ 32	$ —	$ —	$ 127		
International equity	99	50	—	—	149		
Fixed income:						30	28
U.S. Treasury, government, and agency bonds	—	67	—	—	67		
Mortgage- and asset-backed securities	—	1	—	—	1		
Corporate bonds	—	68	—	—	68		
Pooled funds	—	28	—	—	28		
Cash equivalents and other	18	—	—	—	18		
Real estate investments	17	—	—	86	103	13	15
Special situations	—	—	—	9	9	3	2
Private equity	—	—	—	78	78	9	12
Total	$ 229	$ 246	$ —	$ 173	$ 648	100 %	100 %
Southern Power							
Assets:							
Equity:						45 %	43 %
Domestic equity	$ 25	$ 9	$ —	$ —	$ 34		
International equity	27	14	—	—	41		
Fixed income:						30	28
U.S. Treasury, government, and agency bonds	—	18	—	—	18		
Corporate bonds	—	19	—	—	19		
Pooled funds	—	8	—	—	8		
Cash equivalents and other	5	—	—	—	5		
Real estate investments	5	—	—	24	29	13	15
Special situations	—	—	—	2	2	3	2
Private equity	—	—	—	21	21	9	12
Total	$ 62	$ 68	$ —	$ 47	$ 177	100 %	100 %
Southern Company Gas							
Assets:							
Equity:						45 %	43 %
Domestic equity	$ 146	$ 49	$ —	$ —	$ 195		
International equity	152	77	—	—	229		
Fixed income:						30	28
U.S. Treasury, government, and agency bonds	—	104	—	—	104		
Mortgage- and asset-backed securities	—	2	—	—	2		
Corporate bonds	—	105	—	—	105		
Pooled funds	—	43	—	—	43		
Cash equivalents and other	28	1	—	—	29		
Real estate investments	27	—	—	133	160	13	15
Special situations	—	—	—	13	13	3	2
Private equity	—	—	—	121	121	9	12
Total	$ 353	$ 381	$ —	$ 267	$ 1,001	100 %	100 %

	Fair Value Measurements Using						
At December 31, 2021:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**	**Target Allocation**	**Actual Allocation**
			(in millions)				
Southern Company							
Assets:							
Equity:						51 %	53 %
Domestic equity	$ 3,095	$ 1,326	$ —	$ —	$ 4,421		
International equity	2,740	1,402	3	—	4,145		
Fixed income:						23	22
U.S. Treasury, government, and agency bonds	—	1,209	—	—	1,209		
Mortgage- and asset-backed securities	—	10	—	—	10		
Corporate bonds	—	1,752	—	—	1,752		
Pooled funds	—	771	—	—	771		
Cash equivalents and other	405	7	—	—	412		
Real estate investments	706	—	—	2,038	2,744	14	15

Special situations	—	—	—	171	171	3	1
Private equity	—	—	—	1,590	1,590	9	9
Total	$ 6,946	$ 6,477	$ 3	$ 3,799	$ 17,225	100 %	100 %
Alabama Power							
Assets:							
Equity:						51 %	53 %
Domestic equity	$ 743	$ 319	$ —	$ —	$ 1,062		
International equity	659	337	1	—	997		
Fixed income:						23	22
U.S. Treasury, government, and agency bonds	—	291	—	—	291		
Mortgage- and asset-backed securities	—	2	—	—	2		
Corporate bonds	—	421	—	—	421		
Pooled funds	—	186	—	—	186		
Cash equivalents and other	97	2	—	—	99		
Real estate investments	170	—	—	490	660	14	15
Special situations	—	—	—	41	41	3	1
Private equity	—	—	—	382	382	9	9
Total	$ 1,669	$ 1,558	$ 1	$ 913	$ 4,141	100 %	100 %
Georgia Power							
Assets:							
Equity:						51 %	53 %
Domestic equity	$ 972	$ 417	$ —	$ —	$ 1,389		
International equity	861	441	1	—	1,303		
Fixed income:						23	22
U.S. Treasury, government, and agency bonds	—	380	—	—	380		
Mortgage- and asset-backed securities	—	3	—	—	3		
Corporate bonds	—	551	—	—	551		
Pooled funds	—	243	—	—	243		
Cash equivalents and other	127	2	—	—	129		
Real estate investments	222	—	—	641	863	14	15
Special situations	—	—	—	54	54	3	1
Private equity	—	—	—	500	500	9	9
Total	$ 2,182	$ 2,037	$ 1	$ 1,195	$ 5,415	100 %	100 %
Mississippi Power							
Assets:							
Equity:						51 %	53 %
Domestic equity	$ 142	$ 61	$ —	$ —	$ 203		
International equity	126	64	—	—	190		
Fixed income:						23	22
U.S. Treasury, government, and agency bonds	—	55	—	—	55		
Corporate bonds	—	80	—	—	80		
Pooled funds	—	35	—	—	35		
Cash equivalents and other	18	—	—	—	18		
Real estate investments	32	—	—	93	125	14	15
Special situations	—	—	—	8	8	3	1
Private equity	—	—	—	73	73	9	9
Total	$ 318	$ 295	$ —	$ 174	$ 787	100 %	100 %
Southern Power							
Assets:							
Equity:						51 %	53 %
Domestic equity	$ 38	$ 16	$ —	$ —	$ 54		
International equity	34	17	—	—	51		
Fixed income:						23	22
U.S. Treasury, government, and agency bonds	—	15	—	—	15		
Corporate bonds	—	22	—	—	22		
Pooled funds	—	10	—	—	10		
Cash equivalents and other	5	—	—	—	5		
Real estate investments	9	—	—	25	34	14	15
Special situations	—	—	—	2	2	3	1
Private equity	—	—	—	20	20	9	9
Total	$ 86	$ 80	$ —	$ 47	$ 213	100 %	100 %
Southern Company Gas							
Assets:							
Equity:						51 %	53 %
Domestic equity	$ 223	$ 96	$ —	$ —	$ 319		
International equity	197	101	—	—	298		
Fixed income:						23	22
U.S. Treasury, government, and agency bonds	—	87	—	—	87		
Mortgage- and asset-backed securities	—	1	—	—	1		
Corporate bonds	—	126	—	—	126		

Pooled funds	—	56	—	—	56		
Cash equivalents and other	29	—	—	—	29		
Real estate investments	51	—	—	147	198	14	15
Special situations	—	—	—	12	12	3	1
Private equity	—	—	—	115	115	9	9
Total	$ 500	$ 467	$ —	$ 274	$ 1,241	100 %	100 %

The fair values, and actual allocations relative to the target allocations, of the applicable Registrants' other postretirement benefit plan assets at December 31, 2022 and 2021 are presented below.

	Fair Value Measurements Using					
At December 31, 2022:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Southern Company						
Assets:						
Equity:					61 %	59 %
Domestic equity	$ 85	$ 74	$ —	$ 159		
International equity	58	79	—	137		
Fixed income:					30	28
U.S. Treasury, government, and agency bonds	—	43	—	43		
Mortgage- and asset-backed securities	—	1	—	1		
Corporate bonds	—	40	—	40		
Pooled funds	—	79	—	79		
Cash equivalents and other	19	—	—	19		
Trust-owned life insurance	—	406	—	406		
Real estate investments	11	—	51	62	5	7
Special situations	—	—	6	6	1	1
Private equity	—	—	46	46	3	5
Total	$ 173	$ 722	$ 103	$ 998	100 %	100 %
Alabama Power						
Assets:						
Equity:					69 %	65 %
Domestic equity	$ 17	$ 6	$ —	$ 23		
International equity	18	9	—	27		
Fixed income:					23	23
U.S. Treasury, government, and agency bonds	—	12	—	12		
Corporate bonds	—	12	—	12		
Pooled funds	—	7	—	7		
Cash equivalents and other	3	—	—	3		
Trust-owned life insurance	—	252	—	252		
Real estate investments	3	—	16	19	4	7
Special situations	—	—	2	2	1	1
Private equity	—	—	14	14	3	4
Total	$ 41	$ 298	$ 32	$ 371	100 %	100 %
Georgia Power						
Assets:						
Equity:					58 %	56 %
Domestic equity	$ 46	$ 6	$ —	$ 52		
International equity	17	39	—	56		
Fixed income:					35	34
U.S. Treasury, government, and agency bonds	—	10	—	10		
Corporate bonds	—	12	—	12		
Pooled funds	—	40	—	40		
Cash equivalents and other	9	—	—	9		
Trust-owned life insurance	—	154	—	154		
Real estate investments	4	—	15	19	4	5
Special situations	—	—	2	2	1	1
Private equity	—	—	14	14	2	4
Total	$ 76	$ 261	$ 31	$ 368	100 %	100 %
Mississippi Power						
Assets:						
Equity:					37 %	35 %
Domestic equity	$ 3	$ 1	$ —	$ 4		
International equity	3	2	—	5		
Fixed income:					43	41
U.S. Treasury, government, and agency bonds	—	4	—	4		
Corporate bonds	—	2	—	2		
Pooled funds	—	1	—	1		
Cash equivalents and other	2	—	—	2		
Real estate investments	1	—	3	4	11	12
Special situations	—	—	—	—	2	2

Private equity	—	—	2	2	7	10
Total	$ 9	$ 10	$ 5	$ 24	100 %	100 %
Southern Company Gas						
Assets:						
Equity:					72 %	70 %
Domestic equity	$ 2	$ 56	$ —	$ 58		
International equity	2	20	—	22		
Fixed income:					26	27
U.S. Treasury, government, and agency bonds	—	1	—	1		
Corporate bonds	—	1	—	1		
Pooled funds	—	27	—	27		
Cash equivalents and other	1	—	—	1		
Real estate investments	—	—	2	2	1	2
Private equity	—	—	1	1	1	1
Total	$ 5	$ 105	$ 3	$ 113	100 %	100 %

	Fair Value Measurements Using					
At December 31, 2021:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**	**Target Allocation**	**Actual Allocation**
		(in millions)				
Southern Company						
Assets:						
Equity:					64 %	66 %
Domestic equity	$ 123	$ 112	$ —	$ 235		
International equity	73	99	—	172		
Fixed income:					27	25
U.S. Treasury, government, and agency bonds	—	37	—	37		
Corporate bonds	—	50	—	50		
Pooled funds	—	90	—	90		
Cash equivalents and other	14	—	—	14		
Trust-owned life insurance	—	530	—	530		
Real estate investments	20	—	54	74	5	6
Special situations	—	—	5	5	1	—
Private equity	—	—	42	42	3	3
Total	$ 230	$ 918	$ 101	$ 1,249	100 %	100 %
Alabama Power						
Assets:						
Equity:					71 %	69 %
Domestic equity	$ 26	$ 11	$ —	$ 37		
International equity	23	12	—	35		
Fixed income:					21	21
U.S. Treasury, government, and agency bonds	—	10	—	10		
Corporate bonds	—	18	—	18		
Pooled funds	—	6	—	6		
Cash equivalents and other	3	—	—	3		
Trust-owned life insurance	—	341	—	341		
Real estate investments	6	—	17	23	4	7
Special situations	—	—	2	2	1	—
Private equity	—	—	13	13	3	3
Total	$ 58	$ 398	$ 32	$ 488	100 %	100 %
Georgia Power						
Assets:						
Equity:					60 %	62 %
Domestic equity	$ 65	$ 13	$ —	$ 78		
International equity	22	50	—	72		
Fixed income:					33	30
U.S. Treasury, government, and agency bonds	—	9	—	9		
Corporate bonds	—	14	—	14		
Pooled funds	—	46	—	46		
Cash equivalents and other	5	—	—	5		
Trust-owned life insurance	—	189	—	189		
Real estate investments	7	—	16	23	4	5
Special situations	—	—	1	1	1	—
Private equity	—	—	13	13	2	3
Total	$ 99	$ 321	$ 30	$ 450	100 %	100 %
Mississippi Power						
Assets:						
Equity:					43 %	44 %
Domestic equity	$ 4	$ 2	$ —	$ 6		

Domestic equity	$ 4	$ 2	$ —	$ 6		
International equity	4	2	—	6		
Fixed income:					36	34
U.S. Treasury, government, and agency bonds	—	5	—	5		
Corporate bonds	—	2	—	2		
Pooled funds	—	1	—	1		
Cash equivalents and other	1	—	—	1		
Real estate investments	1	—	3	4	11	13
Special situations	—	—	—	—	2	1
Private equity	—	—	2	2	8	8
Total	$ 10	$ 12	$ 5	$ 27	100 %	100 %
Southern Company Gas						
Assets:						
Equity:					72 %	73 %
Domestic equity	$ 3	$ 76	$ —	$ 79		
International equity	2	24	—	26		
Fixed income:					26	24
U.S. Treasury, government, and agency bonds	—	1	—	1		
Corporate bonds	—	1	—	1		
Pooled funds	—	30	—	30		
Cash equivalents and other	2	—	—	2		
Real estate investments	1	—	2	3	1	2
Private equity	—	—	1	1	1	1
Total	$ 8	$ 132	$ 3	$ 143	100 %	100 %

Employee Savings Plan

Southern Company and its subsidiaries also sponsor 401(k) defined contribution plans covering substantially all employees and provide matching contributions up to specified percentages of an employee's eligible pay. Total matching contributions made to the plans for 2022, 2021, and 2020 were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2022	$ 124	$ 26	$ 29	$ 5	$ 3	$ 17
2021	119	26	28	5	2	16
2020	120	26	29	5	2	16

12. STOCK COMPENSATION

Stock-based compensation primarily in the form of Southern Company performance share units (PSU) and restricted stock units (RSU) may be granted through the Equity and Incentive Compensation Plan to Southern Company system employees ranging from line management to executives.

At December 31, 2022, the number of current and former employees participating in stock-based compensation programs for the Registrants was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Number of employees	1,586	221	236	64	45	186

The majority of PSUs and RSUs awarded contain terms where employees become immediately vested in PSUs and RSUs upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately, while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. In addition, the Registrants recognize forfeitures as they occur.

All unvested PSUs and RSUs vest immediately upon a change in control where Southern Company is not the surviving corporation.

Performance Share Units

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; ROE awards based on Southern Company's equity-weighted return over the performance period; and EPS awards based on Southern Company's cumulative EPS over the performance period. EPS awards were last granted in 2017.

The fair value of TSR awards is determined as of the grant date using a Monte Carlo simulation model. In determining the fair value of the TSR awards issued to employees, the expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate is based on the U.S. Treasury yield curve in effect at the

time of grant that covers the performance period of the awards. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of TSR awards granted:

Year Ended December 31	2022	2021	2020
Expected volatility	**29.6%**	30.0%	15.4%
Expected term *(in years)*	**3**	3	3
Interest rate	**1.7%**	0.2%	1.4%
Weighted average grant-date fair value	**$79.69**	$69.06	$77.65

The Registrants recognize TSR award compensation expense on a straight-line basis over the three-year performance period without remeasurement.

The fair values of EPS awards and ROE awards are based on the closing stock price of Southern Company common stock on the date of the grant. The weighted average grant-date fair value of the ROE awards granted during 2022, 2021, and 2020 was $66.87, $59.49, and $68.42, respectively. Compensation expense for EPS and ROE awards is generally recognized ratably over the three-year performance period adjusted for expected changes in EPS and ROE performance. Total compensation cost recognized for vested EPS awards and ROE awards reflects final performance metrics.

Southern Company had 2.2 million unvested PSUs outstanding at December 31, 2021. In February 2022, the PSUs that vested for the three-year performance period ended December 31, 2021 were converted into 2.5 million shares outstanding at a share price of $66.57. During 2022, Southern Company granted 1.3 million PSUs and 1.1 million PSUs were vested or forfeited, resulting in 2.4 million unvested PSUs outstanding at December 31, 2022. In February 2023, the PSUs that vested for the three-year performance period ended December 31, 2022 were converted into 1.8 million

million unvested PSUs outstanding at December 31, 2022. In February 2023, the PSUs that vested for the three-year performance period ended December 31, 2022 were converted into 1.6 million shares outstanding at a weighted average share price of $67.13.

Total PSU compensation cost, and the related tax benefit recognized in income, for the years ended December 31, 2022, 2021, and 2020 are as follows:

	2022	2021	2020
		(in millions)	
Southern Company			
Compensation cost recognized in income	**$ 101**	$ 112	$ 84
Tax benefit of compensation cost recognized in income	**26**	29	22
Southern Company Gas			
Compensation cost recognized in income	**$ 12**	$ 17	$ 13
Tax benefit of compensation cost recognized in income	**4**	4	4

Total PSU compensation cost and the related tax benefit recognized in income were immaterial for all periods presented for all other Registrants. The compensation cost related to the grant of Southern Company PSUs to the employees of each Subsidiary Registrant is recognized in each Subsidiary Registrant's financial statements with a corresponding credit to equity representing a capital contribution from Southern Company.

At December 31, 2022, Southern Company's total unrecognized compensation cost related to PSUs was $31 million and is expected to be recognized over a weighted-average period of approximately 19 months. The total unrecognized compensation cost related to PSUs at December 31, 2022 was immaterial for all other Registrants.

Restricted Stock Units

The fair value of RSUs is based on the closing stock price of Southern Company common stock on the date of the grant. The weighted average grant-date fair values of RSUs granted during 2022, 2021, and 2020 were $67.20, $59.56, and $67.60, respectively. For most RSU awards, one-third of the RSUs vest each year throughout a three-year service period and compensation cost for RSUs is generally recognized over the corresponding one-, two-, or three-year vesting period. Shares of Southern Company common stock are delivered to employees at the end of each vesting period.

Southern Company had 1.1 million RSUs outstanding at December 31, 2021. During 2022, Southern Company granted 0.4 million RSUs and 0.6 million RSUs were vested or forfeited, resulting in 0.9 million unvested RSUs outstanding at December 31, 2022, including RSUs related to employee retention agreements.

For the years ended December 31, 2022, 2021, and 2020, Southern Company's total compensation cost for RSUs recognized in income was $26 million, $32 million, and $29 million, respectively. The related tax benefit also recognized in income was $7 million, $8 million, and $8 million for the years ended December 31, 2022, 2021, and 2020, respectively. Total unrecognized compensation cost related to RSUs at December 31, 2022, which is being recognized over a weighted-average period of approximately 18 months, is immaterial for Southern Company.

Total RSUs outstanding and total compensation cost and related tax benefit for the RSUs recognized in income for the years ended December 31, 2022, 2021, and 2020, as well as the total unrecognized compensation cost at December 31, 2022, were immaterial for all other Registrants. The compensation cost related to the grant of Southern Company RSUs to the employees of each Subsidiary Registrant is recognized in such Subsidiary Registrant's financial statements with a corresponding credit to equity representing a capital contribution from Southern Company.

Stock Options

In 2015, Southern Company discontinued granting stock options. As of December 31, 2017, all stock option awards were vested and compensation cost fully recognized. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur by November 2024. At December 31, 2022, the weighted average remaining contractual term for the options outstanding and exercisable was approximately 10 months.

Southern Company's activity in the stock option program for 2022 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
	(in millions)	
Outstanding at December 31, 2021	2.8	$ 42.95
Exercised	1.8	43.37
Outstanding and Exercisable at December 31, 2022	**1.0**	**$ 42.22**

Southern Company's cash receipts from issuances related to stock options exercised under the share-based payment arrangements for the years ended December 31, 2022, 2021, and 2020 were $75 million, $66 million, and $66 million, respectively.

At December 31, 2022, the aggregate intrinsic value for options outstanding and exercisable was $29 million for Southern Company and immaterial for all other Registrants.

Total intrinsic value of options exercised, and the related tax benefit, for the years ended December 31, 2022, 2021, and 2020 are presented below for Southern Company and Georgia Power and were immaterial for all other Registrants:

Year Ended December 31	**2022**	2021	2020
		(in millions)	
Southern Company			
Intrinsic value of options exercised	**$ 49**	$ 34	$ 38
Tax benefit of options exercised	**12**	7	9
Georgia Power			
Intrinsic value of options exercised	**$ 15**	$ 14	$ 9
Tax benefit of options exercised	**4**	3	2

13. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is

minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of each Registrant of what a market participant would use in pricing an asset or liability. If there is little available market data, then each Registrant's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

Net asset value as a practical expedient is the classification used for assets that do not have readily determined fair values. Fund managers value the assets using various inputs and techniques depending on the nature of the underlying investments.

At December 31, 2022, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using	
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Net Asset Value

At December 31, 2022:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Southern Company					
Assets:					
Energy-related derivatives[a]	$ 18	$ 181	$ —	$ —	$ 199
Interest rate derivatives	—	12	—	—	12
Investments in trusts:[b][c]					
Domestic equity	651	178	—	—	829
Foreign equity	125	150	—	—	275
U.S. Treasury and government agency securities	—	285	—	—	285
Municipal bonds	—	51	—	—	51
Pooled funds – fixed income	—	7	—	—	7
Corporate bonds	—	412	—	—	412
Mortgage and asset backed securities	—	90	—	—	90
Private equity	—	—	—	161	161
Cash and cash equivalents	4	—	—	—	4
Other	37	12	—	—	49
Cash equivalents	1,427	20	—	—	1,447
Other investments	9	26	—	—	35
Total	$ 2,271	$ 1,424	$ —	$ 161	$ 3,856
Liabilities:					
Energy-related derivatives[a]	$ 32	$ 178	$ —	$ —	$ 210
Interest rate derivatives	—	302	—	—	302
Foreign currency derivatives	—	216	—	—	216
Contingent consideration	—	—	12	—	12
Other	—	13	—	—	13
Total	$ 32	$ 709	$ 12	$ —	$ 753
Alabama Power					
Assets:					
Energy-related derivatives	$ —	$ 62	$ —	$ —	$ 62
Nuclear decommissioning trusts:[b]					
Domestic equity	396	169	—	—	565
Foreign equity	125	—	—	—	125
U.S. Treasury and government agency securities	—	19	—	—	19
Municipal bonds	—	1	—	—	1
Corporate bonds	—	225	—	—	225
Mortgage and asset backed securities	—	22	—	—	22
Private equity	—	—	—	161	161
Other	7	—	—	—	7
Cash equivalents	438	20	—	—	458
Other investments	—	26	—	—	26
Total	$ 966	$ 544	$ —	$ 161	$ 1,671
Liabilities:					
Energy-related derivatives	$ —	$ 39	$ —	$ —	$ 39
Georgia Power					
Assets:					
Energy-related derivatives	$ —	$ 42	$ —	$ —	$ 42
Nuclear decommissioning trusts:[b][c]					
Domestic equity	255	1	—	—	256
Foreign equity	—	149	—	—	149
U.S. Treasury and government agency securities	—	266	—	—	266
Municipal bonds	—	50	—	—	50
Corporate bonds	—	187	—	—	187
Mortgage and asset backed securities	—	68	—	—	68
Other	30	12	—	—	42
Cash equivalents	355	—	—	—	355
Total	$ 640	$ 775	$ —	$ —	$ 1,415
Liabilities:					
Energy-related derivatives	$ —	$ 62	$ —	$ —	$ 62
Mississippi Power					
Assets:					
Energy-related derivatives	$ —	$ 59	$ —	$ —	$ 59
Cash equivalents	47	—	—	—	47
Total	$ 47	$ 59	$ —	$ —	$ 106
Liabilities:					
Energy-related derivatives	$ —	$ 32	$ —	$ —	$ 32
Southern Power					

Assets:					
Energy-related derivatives	$ —	$ 8	$ —	$ —	$ 8
Liabilities:					
Energy-related derivatives	$ —	$ 12	$ —	$ —	$ 12
Foreign currency derivatives	—	47	—	—	47
Contingent consideration	—	—	12	—	12
Other	—	13	—	—	13
Total	$ —	$ 72	$ 12	$ —	$ 84
Southern Company Gas					
Assets:					
Energy-related derivatives[a]	$ 18	$ 10	$ —	$ —	$ 28
Non-qualified deferred compensation trusts:					
Domestic equity	—	8	—	—	8
Foreign equity	—	1	—	—	1
Pooled funds - fixed income	—	7	—	—	7
Cash and cash equivalents	4	—	—	—	4
Cash equivalents	50	—	—	—	50
Total	$ 72	$ 26	$ —	$ —	$ 98
Liabilities:					
Energy-related derivatives[a][b]	$ 32	$ 33	$ —	$ —	$ 65
Interest rate derivatives	—	86	—	—	86
Total	$ 32	$ 119	$ —	$ —	$ 151

(a) Excludes cash collateral of $41 million.

(b) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies. See Note 6 under "Nuclear Decommissioning" for additional information.

(c) Includes investment securities pledged to creditors and collateral received and excludes payables related to the securities lending program. See Note 6 under "Nuclear Decommissioning" for additional information.

At December 31, 2021, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using				
At December 31, 2021:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Southern Company					
Assets:					
Energy-related derivatives[a]	$ 24	$ 195	$ —	$ —	$ 219
Interest rate derivatives	—	19	—	—	19
Investments in trusts:[b][c]					
Domestic equity	791	225	—	—	1,016
Foreign equity	165	188	—	—	353
U.S. Treasury and government agency securities	—	314	—	—	314
Municipal bonds	—	56	—	—	56
Pooled funds – fixed income	—	13	—	—	13
Corporate bonds	1	522	—	—	523
Mortgage and asset backed securities	—	93	—	—	93
Private equity	—	—	—	150	150
Cash and cash equivalents	2	—	—	—	2
Other	22	25	—	—	47
Cash equivalents	1,160	14	—	—	1,174
Other investments	9	35	—	—	44
Total	$ 2,174	$ 1,699	$ —	$ 150	$ 4,023
Liabilities:					
Energy-related derivatives[a]	$ 10	$ 36	$ —	$ —	$ 46
Interest rate derivatives	—	29	—	—	29
Foreign currency derivatives	—	79	—	—	79
Contingent consideration	—	—	14	—	14
Other	—	13	—	—	13
Total	$ 10	$ 157	$ 14	$ —	$ 181
Alabama Power					
Assets:					
Energy-related derivatives	$ —	$ 55	$ —	$ —	$ 55
Nuclear decommissioning trusts:[b]					
Domestic equity	468	216	—	—	684
Foreign equity	165	—	—	—	165
U.S. Treasury and government agency securities	—	21	—	—	21
Municipal bonds	—	1	—	—	1
Corporate bonds	1	271	—	—	272
Mortgage and asset backed securities	—	22	—	—	22
Private equity	—	—	—	150	150
Other	9	—	—	—	9
Cash equivalents	839	14			853

Cash equivalents	839	14	—	—	853
Other investments	—	35	—	—	35
Total	$ 1,482	$ 635	$ —	$ 150	$ 2,267
Liabilities:					
Energy-related derivatives	$ —	$ 11	$ —	$ —	$ 11
Georgia Power					
Assets:					
Energy-related derivatives	$ —	$ 75	$ —	$ —	$ 75
Nuclear decommissioning trusts:[b][c]					
Domestic equity	323	1	—	—	324
Foreign equity	—	185	—	—	185
U.S. Treasury and government agency securities	—	293	—	—	293
Municipal bonds	—	55	—	—	55
Corporate bonds	—	251	—	—	251
Mortgage and asset backed securities	—	71	—	—	71
Other	13	25	—	—	38
Total	$ 336	$ 956	$ —	$ —	$ 1,292
Liabilities:					
Energy-related derivatives	$ —	$ 8	$ —	$ —	$ 8
Mississippi Power					
Assets:					
Energy-related derivatives	$ —	$ 56	$ —	$ —	$ 56
Cash equivalents	40	—	—	—	40
Total	$ 40	$ 56	$ —	$ —	$ 96
Liabilities:					
Energy-related derivatives	$ —	$ 5	$ —	$ —	$ 5
Southern Power					
Assets:					
Energy-related derivatives	$ —	$ 4	$ —	$ —	$ 4
Liabilities:					
Foreign currency derivatives	$ —	$ 16	$ —	$ —	$ 16
Contingent consideration	—	—	14	—	14
Other	—	13	—	—	13
Total	$ —	$ 29	$ 14	$ —	$ 43
Southern Company Gas					
Assets:					
Energy-related derivatives[a]	$ 24	$ 5	$ —	$ —	$ 29
Interest rate derivatives	—	6	—	—	6
Non-qualified deferred compensation trusts:					
Domestic equity	—	8	—	—	8
Foreign equity	—	3	—	—	3
Pooled funds - fixed income	—	13	—	—	13
Cash equivalents	2	—	—	—	2
Total	$ 26	$ 35	$ —	$ —	$ 61
Liabilities:					
Energy-related derivatives[a][b]	$ 10	$ 12	$ —	$ —	$ 22
Interest rate derivatives	—	5	—	—	5
Total	$ 10	$ 17	$ —	$ —	$ 27

(a) Excludes immaterial cash collateral.

(b) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies. See Note 6 under "Nuclear Decommissioning" for additional information.

(c) Includes investment securities pledged to creditors and collateral received and excludes payables related to the securities lending program. See Note 6 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded and over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 14 for additional information on how these derivatives are used.

For fair value measurements of the investments within the nuclear decommissioning trusts and the non-qualified deferred compensation trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day

through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. See Note 6 under "Nuclear Decommissioning" for additional information.

Southern Power has contingent payment obligations related to certain acquisitions whereby it is primarily obligated to make generation-based payments to the seller, which commenced at the commercial operation of the respective facility and continue through 2026. The obligations are categorized as Level 3 under Fair Value Measurements as the fair value is determined using significant unobservable inputs for the forecasted facility generation in MW-hours, as well as other inputs such as a fixed dollar amount per MW-hour, and a discount rate. The fair value of contingent consideration reflects the net present value of expected payments and any periodic change arising from forecasted generation is expected to be immaterial.

Southern Power also has payment obligations through 2040 whereby it must reimburse the transmission owners for interconnection facilities and network upgrades constructed to support connection of a Southern Power generating facility to the transmission system. The obligations are categorized as Level 2 under Fair Value Measurements as the fair value is determined using observable inputs for the contracted amounts and reimbursement period, as well as a discount rate. The fair value of the obligations reflects the net present value of expected payments.

"Other investments" include investments traded in the open market that have maturities greater than 90 days, which are categorized as Level 2 under Fair Value Measurements and are comprised of corporate bonds, bank certificates of deposit, treasury bonds, and/or agency bonds.

The fair value measurements of private equity investments held in Alabama Power's nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient totaled $161 million and $150 million at December 31, 2022 and 2021, respectively. Unfunded commitments related to the private equity investments totaled $78 million and $69 million at December 31, 2022 and 2021, respectively. Private equity investments include high-quality private equity funds across several market sectors and funds that invest in real estate assets. Private equity funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated.

At December 31, 2022 and 2021, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Southern Company[*]	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas[*]
			(in billions)			
At December 31, 2022:						
Long-term debt, including securities due within one year:						
Carrying amount	**$ 54.6**	**$ 10.6**	**$ 14.7**	**$ 1.5**	**$ 3.0**	**$ 7.4**
Fair value	**48.6**	**9.2**	**13.0**	**1.3**	**2.8**	**6.5**
At December 31, 2021:						
Long-term debt, including securities due within one year:						
Carrying amount	$ 52.1	$ 9.7	$ 13.6	$ 1.5	$ 3.7	$ 6.9
Fair value	57.1	10.9	15.1	1.6	4.1	7.8

* The long-term debt of Southern Company Gas is recorded at amortized cost, including the fair value adjustments at the effective date of the 2016 merger with Southern Company. Southern Company Gas amortizes the fair value adjustments over the remaining lives of the respective bonds, the latest being through 2043.

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Registrants.

14. DERIVATIVES

The Registrants are exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Prior to the sale of Sequent on July 1, 2021, Southern Company Gas' wholesale gas operations used various contracts in its commercial activities that generally met the definition of derivatives. For the traditional electric operating companies, Southern Power, and Southern Company Gas' other businesses, each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 13 for additional fair value information. In the statements of cash flows, any cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities. Any cash impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with the classification of the hedged interest or principal, respectively. See Note 1 under "Financial Instruments" for additional information. See Note 15 under "Southern Company Gas" for additional information regarding the sale of Sequent.

Energy-Related Derivatives

The Subsidiary Registrants enter into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional electric operating companies and the natural gas distribution utilities have limited exposure to market volatility in energy-related commodity prices. Each of the traditional electric operating companies and certain of the natural gas distribution utilities of Southern Company Gas manage fuel-hedging programs, implemented per the guidelines of their respective state PSCs or other applicable state regulatory agencies, through the use of financial derivative contracts, which are expected to continue to mitigate price volatility. The traditional electric operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in energy-related commodity prices because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional electric operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted capacity is used to sell electricity. Southern Company Gas retains exposure to price changes that can, in a volatile energy market, be material and can adversely affect its results of operations.

Southern Company Gas also enters into weather derivative contracts as economic hedges in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in operating revenues.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts designated as regulatory hedges relate primarily to the traditional electric operating companies' and the natural gas distribution utilities' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through an approved cost recovery mechanism.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in AOCI before being recognized in the statements of income in the same period and in the same income statement line item as the earnings effect of the hedged transactions.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric and natural gas industries. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2022, the net volume of energy-related derivative contracts for natural gas positions, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company[*]	431	2030	2025
Alabama Power	111	2026	—
Georgia Power	125	2026	—
Mississippi Power	94	2027	—
Southern Power	8	2030	2023
Southern Company Gas[*]	93	2025	2025

Southern Company Gas *	93	2023	2023	

* Southern Company Gas' derivative instruments include both long and short natural gas positions. A long position is a contract to purchase natural gas and a short position is a contract to sell natural gas. Southern Company Gas' volume represents the net of long natural gas positions of 98 million mmBtu and short natural gas positions of 5 million mmBtu at December 31, 2022, which is also included in Southern Company's total volume. See Note 15 under "Southern Company Gas" for information regarding the sale of Sequent.

In addition to the volumes discussed above, the traditional electric operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess natural gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 23 million mmBtu for Southern Company, which includes 6 million mmBtu for Alabama Power, 8 million mmBtu for Georgia Power, 3 million mmBtu for Mississippi Power, and 6 million mmBtu for Southern Power.

For cash flow hedges of energy-related derivatives, the estimated pre-tax gains (losses) expected to be reclassified from AOCI to earnings for the year ending December 31, 2023 are $(27) million for Southern Company, $(11) million for Southern Power, and $(16) million for Southern Company Gas.

Interest Rate Derivatives

Southern Company and certain subsidiaries may enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the derivatives' fair value gains or losses are recorded in OCI and are reclassified into earnings at the same time and presented on the same income statement line item as the earnings effect of the hedged transactions. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value

gains or losses are both recorded directly to earnings on the same income statement line item. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

At December 31, 2022, the following interest rate derivatives were outstanding:

	Notional Amount	Weighted Average Interest Rate Paid	Interest Rate Received	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2022
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
Southern Company parent	$ 400	3.50%	N/A	June 2033	$ 12
Fair Value Hedges of Existing Debt					
Southern Company parent	400	1-month LIBOR + 0.68%	1.75%	March 2028	(55)
Southern Company parent	1,000	1-month LIBOR + 2.36%	3.70%	April 2030	(161)
Southern Company Gas	500	1-month LIBOR + 0.38%	1.75%	January 2031	(86)
Southern Company	$ 2,300				$ (290)

For cash flow hedges of interest rate derivatives, the estimated pre-tax gains (losses) expected to be reclassified from AOCI to interest expense for the year ending December 31, 2023 are $(16) million for Southern Company and immaterial for the other Registrants. Deferred gains and losses related to interest rate derivatives are expected to be amortized into earnings through 2052 for Southern Company, Alabama Power, and Georgia Power, 2028 for Mississippi Power, and 2046 for Southern Company Gas.

Foreign Currency Derivatives

Southern Company and certain subsidiaries, including Southern Power, may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to forecasted transactions are accounted for as cash flow hedges where the derivatives' fair value gains or losses are recorded in OCI and are reclassified into earnings at the same time and on the same income statement line as the earnings effect of the hedged transactions, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings on the same income statement line item, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Southern Company has elected to exclude the cross-currency basis spread from the assessment of effectiveness in the fair value hedges of its foreign currency risk and record any difference between the change in the fair value of the excluded components and the amounts recognized in earnings as a component of OCI.

At December 31, 2022, the following foreign currency derivatives were outstanding:

	Pay Notional	Pay Rate	Receive Notional	Receive Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2022
	(in millions)		*(in millions)*			*(in millions)*
Cash Flow Hedges of Existing Debt						
Southern Power	$ 564	3.78%	€ 500	1.85%	June 2026	$ (47)
Fair Value Hedges of Existing Debt						
Southern Company parent	1,476	3.39%	1,250	1.88%	September 2027	(169)
Southern Company	$ 2,040		€ 1,750			$ (216)

For cash flow hedges of foreign currency derivatives, the estimated pre-tax losses expected to be reclassified from AOCI to earnings for the year ending December 31, 2023 are $11 million for Southern Power.

Derivative Financial Statement Presentation and Amounts

The Registrants enter into derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Southern Company and certain subsidiaries also utilize master netting agreements to mitigate exposure to counterparty credit risk. These agreements may contain provisions that permit netting across product lines and against cash collateral. The fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties.

At December 31, 2022 and 2021, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

	2022		2021	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
		(in millions)		
Southern Company				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Assets from risk management activities/Other current liabilities	**$ 123**	**$ 121**	$ 129	$ 30
Other deferred charges and assets/Other deferred credits and liabilities	**52**	**44**	72	6
Total derivatives designated as hedging instruments for regulatory purposes	**175**	**165**	201	36
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Assets from risk management activities/Other current liabilities	**3**	**27**	7	5
Other deferred charges and assets/Other deferred credits and liabilities	**6**	**4**	1	—
Interest rate derivatives:				

Interest rate derivatives:				
Assets from risk management activities/Other current liabilities	**12**	**62**	19	—
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**240**	—	29
Foreign currency derivatives:				
Assets from risk management activities/Other current liabilities	**—**	**34**	—	39
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**182**	—	40
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**21**	**549**	27	113
Energy-related derivatives not designated as hedging instruments				
Assets from risk management activities/Other current liabilities	**13**	**13**	9	4
Other deferred charges and assets/Other deferred credits and liabilities	**2**	**1**	1	—
Total derivatives not designated as hedging instruments	**15**	**14**	10	4
Gross amounts recognized	**211**	**728**	238	153
Gross amounts offset[a]	**(70)**	**(111)**	(25)	(28)
Net amounts recognized in the Balance Sheets[b]	**$ 141**	**$ 617**	$ 213	$ 125
Alabama Power[c]				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Other current assets/Other current liabilities	**$ 42**	**$ 21**	$ 30	$ 9
Other deferred charges and assets/Other deferred credits and liabilities	**20**	**18**	25	2
Total derivatives designated as hedging instruments for regulatory purposes	**62**	**39**	55	11
Gross amounts offset	**(24)**	**(24)**	(5)	(5)
Net amounts recognized in the Balance Sheets	**$ 38**	**$ 15**	$ 50	$ 6
Georgia Power				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Assets from risk management activities/Other current liabilities	**$ 36**	**$ 43**	$ 54	$ 6
Other deferred charges and assets/Other deferred credits and liabilities	**6**	**18**	21	2
Total derivatives designated as hedging instruments for regulatory purposes	**42**	**61**	75	8
Energy-related derivatives not designated as hedging instruments				
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**1**	—	—
Gross amounts recognized	**42**	**62**	75	8
Gross amounts offset	**(21)**	**(21)**	(8)	(8)
Net amounts recognized in the Balance Sheets	**$ 21**	**$ 41**	$ 67	$ —
Mississippi Power[c]				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Assets from risk management activities/Other current liabilities	**$ 33**	**$ 24**	$ 30	$ 3
Other deferred charges and assets/Other deferred credits and liabilities	**26**	**8**	26	2
Total derivatives designated as hedging instruments for regulatory purposes	**59**	**32**	56	5
Gross amounts offset	**(17)**	**(17)**	(4)	(4)
Net amounts recognized in the Balance Sheets	**$ 42**	**$ 15**	$ 52	$ 1
Southern Power				
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ —**	**$ 12**	$ 2	$ —
Other deferred charges and assets/Other deferred credits and liabilities	**5**	**—**	1	—
Foreign currency derivatives:				
Other current assets/Other current liabilities	**—**	**11**	—	16
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**36**	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**5**	**59**	3	16
Energy-related derivatives not designated as hedging instruments				
Other current assets/Other current liabilities	**2**	**—**	1	—
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**—**	—	—
Total derivatives not designated as hedging instruments	**3**	**—**	1	—
Net amounts recognized in the Balance Sheets	**$ 8**	**$ 59**	$ 4	$ 16
Southern Company Gas				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Other current assets/Other current liabilities	**$ 12**	**$ 33**	$ 15	$ 12
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Other current liabilities	**3**	**15**	5	5
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**4**	—	—
Interest rate derivatives:				
Other current assets/Other current liabilities	**—**	**14**	6	—
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**72**	—	6
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**4**	**105**	11	11
Energy-related derivatives not designated as hedging instruments				
Other current assets/Other current liabilities	**11**	**12**	8	4
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**1**	1	—
Total derivatives not designated as hedging instruments	**12**	**13**	9	4
Gross amounts recognized	**28**	**151**	35	27
Gross amounts offset[a]	**—**	**(41)**	(8)	(11)

Net amounts recognized in the Balance Sheets[b]	**$ 28**	**$ 110**	$ 27	$ 16

(a) Gross amounts offset includes cash collateral held on deposit in broker margin accounts of $41 million and $3 million at December 31, 2022 and 2021, respectively.

(b) Net amounts of derivative instruments outstanding exclude immaterial premium and intrinsic value associated with weather derivatives for all periods presented.

(c) Energy-related derivatives not designated as hedging instruments were immaterial at December 31, 2022 and there were no such instruments at December 31, 2021.

At December 31, 2022 and 2021, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized in the Balance Sheets

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
At December 31, 2022:					
Energy-related derivatives:					
Other regulatory assets, current	$ (71)	$ (8)	$ (26)	$ (13)	$ (24)
Other regulatory assets, deferred	(23)	(7)	(14)	(2)	—
Other regulatory liabilities, current	72	29	19	22	2
Other regulatory liabilities, deferred	31	9	2	20	—
Total energy-related derivative gains (losses)	$ 9	$ 23	$ (19)	$ 27	$ (22)
At December 31, 2021:					
Energy-related derivatives:					
Other regulatory assets, current	$ (17)	$ (6)	$ —	$ —	$ (11)
Other regulatory liabilities, current	107	28	48	27	4
Other regulatory liabilities, deferred	65	22	19	24	—
Total energy-related derivative gains (losses)	$ 155	$ 44	$ 67	$ 51	$ (7)

For the years ended December 31, 2022, 2021, and 2020, the pre-tax effects of cash flow and fair value hedge accounting on AOCI for the applicable Registrants were as follows:

Gain (Loss) From Derivatives Recognized in OCI	2022	2021	2020
		(in millions)	
Southern Company			
Cash flow hedges:			
Energy-related derivatives	$ 3	$ 34	$ (8)
Interest rate derivatives	46	5	(26)
Foreign currency derivatives	(105)	(103)	48
Fair value hedges[*]:			
Foreign currency derivatives	(24)	(3)	—
Total	$ (80)	$ (67)	$ 14
Georgia Power			
Interest rate derivatives	$ 31	$ —	$ (3)
Southern Power			
Cash flow hedges:			
Energy-related derivatives	$ (15)	$ 12	$ (2)
Foreign currency derivatives	(105)	(103)	48
Total	$ (120)	$ (91)	$ 46
Southern Company Gas			
Cash flow hedges:			
Energy-related derivatives	$ 18	$ 22	$ (6)
Interest rate derivatives	—	—	(23)
Total	$ 18	$ 22	$ (29)

* Represents amounts excluded from the assessment of effectiveness for which the difference between changes in fair value and periodic amortization is recorded in OCI.

The pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on AOCI were immaterial for the other Registrants for all years presented.

The pre-tax effects of cash flow and fair value hedge accounting on income for the years ended December 31, 2022, 2021, and 2020 were as follows:

Location and Amount of Gain (Loss) Recognized in Income on Cash Flow and Fair Value Hedging Relationships	2022	2021	2020
		(in millions)	
Southern Company			
Total cost of natural gas	**$ 3,004**	**$ 1,619**	**$ 972**
Gain (loss) on energy-related cash flow hedges[a]	37	17	(8)
Total depreciation and amortization	**3,663**	**3,565**	**3,518**
Gain (loss) on energy-related cash flow hedges[a]	(5)	9	(3)
Total interest expense, net of amounts capitalized	**(2,022)**	**(1,837)**	**(1,821)**
Gain (loss) on interest rate cash flow hedges[a]	(25)	(27)	(26)
Gain (loss) on foreign currency cash flow hedges[a]	(19)	(24)	(23)
Gain (loss) on interest rate fair value hedges[b]	(291)	(30)	27
Total other income (expense), net	**500**	**456**	**336**
Gain (loss) on foreign currency cash flow hedges[a][c]	(83)	(104)	114
Gain (loss) on foreign currency fair value hedges	(106)	(63)	—
Amount excluded from effectiveness testing recognized in earnings	24	3	—
Southern Power			
Total depreciation and amortization	**$ 516**	**$ 517**	**$ 494**
Gain (loss) on energy-related cash flow hedges[a]	(5)	9	(3)

Gain (loss) on energy-related cash flow hedges			
Total interest expense, net of amounts capitalized	**(138)**	**(147)**	**(151)**
Gain (loss) on foreign currency cash flow hedges[a]	(19)	(24)	(23)
Total other income (expense), net	**7**	**10**	**19**
Gain (loss) on foreign currency cash flow hedges[a][c]	(83)	(104)	114
Southern Company Gas			
Total cost of natural gas	**$ 3,004**	**$ 1,619**	**$ 972**
Gain (loss) on energy-related cash flow hedges[a]	37	17	(8)
Total interest expense, net of amounts capitalized	**(263)**	**(238)**	**(231)**
Gain (loss) on interest rate cash flow hedges[a]	(4)	—	—
Gain (loss) on interest rate fair value hedges[b]	(86)	—	—

(a) Reclassified from AOCI into earnings.

(b) For fair value hedges, changes in the fair value of the derivative contracts are generally equal to changes in the fair value of the underlying debt and have no material impact on income.

(c) The reclassification from AOCI into other income (expense), net completely offsets currency gains and losses arising from changes in the U.S. currency exchange rates used to record the euro-denominated notes.

The pre-tax effects of cash flow and fair value hedge accounting on income for interest rate derivatives and energy-related derivatives were immaterial for the traditional electric operating companies for all years presented.

At December 31, 2022 and 2021, the following amounts were recorded on the balance sheets related to cumulative basis adjustments for fair value hedges:

	Carrying Amount of the Hedged Item		Cumulative Amount of Fair Value Hedging Adjustment included in Carrying Amount of the Hedged Item	
Balance Sheet Location of Hedged Items	**At December 31, 2022**	**At December 31, 2021**	**At December 31, 2022**	**At December 31, 2021**
	(in millions)		*(in millions)*	
Southern Company				
Long-term debt	**$ (2,927)**	$ (3,280)	**$ 282**	$ 9
Southern Company Gas				
Long-term debt	**$ (415)**	$ (493)	**$ 81**	$ 2

The pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income of Southern Company and Southern Company Gas for the years ended December 31, 2022, 2021, and 2020 were as follows:

		Gain (Loss)		
Derivatives in Non-Designated Hedging Relationships	**Statements of Income Location**	**2022**	**2021**	**2020**
			(in millions)	
Energy-related derivatives	Natural gas revenues[*]	**$ (11)**	$ (117)	$ 134
	Cost of natural gas	**(65)**	(27)	15
Total derivatives in non-designated hedging relationships		**$ (76)**	$ (144)	$ 149

(*) Excludes the impact of weather derivatives recorded in natural gas revenues of $(7) million and $9 million for 2022 and 2020, respectively, as they are accounted for based on intrinsic value rather than fair value. There was no weather derivatives impact for 2021.

The pre-tax effects of energy-related derivatives not designated as hedging instruments were immaterial for all other Registrants for all years presented.

Contingent Features

The Registrants do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. At December 31, 2022, the Registrants had no collateral posted with derivative counterparties to satisfy these arrangements.

For Southern Company and Southern Power, the fair value of interest rate derivative liabilities with contingent features and the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $78 million and $23 million, respectively, at December 31, 2022. For the traditional electric operating companies and Southern Power, energy-related derivative liabilities with contingent features and the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were immaterial at December 31, 2022. The maximum potential collateral requirements arising from the credit-risk-related contingent features for the traditional electric operating companies and Southern Power include certain agreements that could require collateral in the event that one or more Southern Company power pool participants has a credit rating change to below investment grade.

Alabama Power and Southern Power maintain accounts with certain regional transmission organizations to facilitate financial derivative transactions and they may be required to post collateral based on the value of the positions in these accounts and the associated margin requirements. At December 31, 2022, cash collateral posted in these accounts was $15 million for Southern Power and immaterial for Alabama Power. Southern Company Gas maintains accounts with brokers or the clearing houses of certain exchanges to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the

associated margin requirements, Southern Company Gas may be required to deposit cash into these accounts. At December 31, 2022, cash collateral held on deposit in broker margin accounts was $41 million.

The Registrants are exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Registrants only enter into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Registrants have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate their exposure to counterparty credit risk.

Southern Company Gas uses established credit policies to determine and monitor the creditworthiness of counterparties, including requirements to post collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. Prior to entering a physical transaction, Southern Company Gas assigns its counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements. Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary.

Southern Company Gas utilizes netting agreements whenever possible to mitigate exposure to counterparty credit risk. Netting agreements enable Southern Company Gas to net certain assets and liabilities by counterparty across product lines and against cash collateral, provided the netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, counterparties are settled net, they are recorded on a gross basis on the balance sheet as energy marketing receivables and energy marketing payables.

The Registrants do not anticipate a material adverse effect on their respective financial statements as a result of counterparty nonperformance.

15. ACQUISITIONS AND DISPOSITIONS

None of the dispositions discussed herein, both individually and combined, represented a strategic shift in operations for the applicable Registrants that has, or is expected to have, a major effect on its operations and financial results; therefore, none of the assets related to the sales have been classified as discontinued operations for any of the periods presented.

Southern Company

In connection with the annual impairment analysis of a leveraged lease investment during the fourth quarter 2020, Southern Company management concluded that the estimated residual value of the generation assets should be reduced due to significant uncertainty as to whether the related natural gas generation assets would continue to operate at the end of the lease term in 2040 and recorded a $34 million ($17 million after tax) impairment charge. Also during the fourth quarter 2020, Southern Company management initiated steps to sell the investment and reclassified it as held for sale. In the fourth quarter 2020 and the second quarter 2021, additional charges of $18 million ($14 million after tax) and $7 million ($6 million after tax), respectively, were recorded to further reduce the investment to its estimated fair value, less costs to sell. In October 2021, Southern Company completed the sale to the lessee for $45 million. No gain or loss was recognized on the sale; however, it did result in the recognition of approximately $16 million of additional tax benefits.

In December 2021, Southern Company completed the termination of its leasehold interest in assets associated with its two international leveraged lease projects and received cash proceeds of approximately $673 million after the accelerated exercise of the lessee's purchase options. The pre-tax gain associated with the transaction was approximately $93 million ($99 million gain after tax).

Alabama Power

In 2020, Alabama Power completed its acquisition of the Central Alabama Generating Station, an approximately 885-MW combined cycle generation facility in Autauga County, Alabama. The transaction was accounted for as a business combination. The total purchase price was $461 million, of which $452 million was related to net assets recorded within property, plant, and

equipment on the balance sheet and reflected in property additions within the investing section of the statement of cash flows. The remainder primarily related to inventory, current receivables, and accounts payable. Alabama Power assumed an existing power sales agreement under which the full output of the generating facility remains committed to another third party through May 2023. During the remaining term, the revenues from the power sales agreement are expected to substantially offset the associated costs of operation. See Note 9 under "Lessor" for additional information.

On September 30, 2022, Alabama Power completed its acquisition of the Calhoun Generating Station, which was accounted for as an asset acquisition. The total purchase price was $179 million, of which $171 million was related to net assets recorded within property, plant, and equipment on the balance sheet and reflected in property additions within the investing section of the statement of cash flows. The remainder primarily related to fossil fuel stock and materials and supplies.

See Note 2 under "Alabama Power – Certificates of Convenience and Necessity" for additional information.

Southern Power

Southern Power's acquisition-related costs for the projects discussed under "Asset Acquisitions" and "Construction Projects" below were expensed as incurred and were not material for any of the years presented. There were no asset acquisitions during 2022.

Asset Acquisitions

Project Facility	Resource	Seller	Approximate Nameplate Capacity (*MW*)	Location	Southern Power Ownership Percentage	COD	PPA Contract Period
Asset Acquisitions During 2021							
Deuel Harvest[a]	Wind	Invenergy Renewables LLC	300	Deuel County, SD	100% of Class B	February 2021	25 years and 15 years
Asset Acquisitions During 2020							
Beech Ridge II[b]	Wind	Invenergy Renewables LLC	56	Greenbrier County, WV	100% of Class A	May 2020	12 years

(a) In March 2021, Southern Power acquired a controlling interest in the project from Invenergy Renewables LLC and completed a tax equity transaction whereby it sold the Class A membership interests in the project. Southern Power consolidates the project's operating results in its financial statements and the tax equity partner and Invenergy Renewables LLC each own a noncontrolling interest.

(b) In May 2020, Southern Power purchased a controlling interest and now consolidates the project's operating results in its financial statements. The Class B member owns the noncontrolling interest.

Construction Projects

During 2022, Southern Power completed construction of and placed in service the remaining 40 MWs of the Tranquillity battery energy storage facility and the remaining 15 MWs of the Garland battery energy storage facility. See Note 9 under "Lessor" for additional information.

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	COD	PPA Contract Period
Projects Completed During 2022					
Garland Solar Storage[a]	Battery energy storage	88	Kern County, CA	September 2021 through February 2022[b]	20 years
Tranquillity Solar Storage[a]	Battery energy storage	72	Fresno County, CA	November 2021 through March 2022[c]	20 years
Projects Completed During 2021					
Glass Sands[d]	Wind	118	Murray County, OK	November 2021	12 years
Projects Completed During 2020					
Skookumchuck[e]	Wind	136	Lewis and Thurston Counties, WA	November 2020	20 years
Reading[f]	Wind	200	Osage and Lyon Counties, KS	May 2020	12 years

(a) In December 2020, Southern Power restructured its ownership of the project, while retaining the controlling interests, by contributing the Class A membership interests to an existing partnership and selling 100% of the Class B membership interests. During 2021, Southern Power further restructured its ownership in the battery energy storage projects and completed tax equity transactions whereby it sold the Class A membership interests in the projects. Southern Power consolidates each project's operating results in its financial statements and the tax equity partner and two other partners each own a noncontrolling interest.

(b) The facility has a total capacity of 88 MWs, of which 73 MWs were placed in service in 2021 and 15 MWs were placed in service in February 2022.

(c) The facility has a total capacity of 72 MWs, of which 32 MWs were placed in service in 2021 and 40 MWs were placed in service in March 2022.

(d) In December 2020, Southern Power purchased 100% of the membership interests of the Glass Sands facility.

(e) In November 2020, Southern Power completed a tax equity transaction whereby it received $121 million, resulting in 100% ownership of the Class B membership interests. Southern Power subsequently sold a noncontrolling interest in the Class B membership interests and now retains the controlling ownership interest in the facility.

(f) In June 2020, Southern Power completed a tax equity transaction whereby it received $156 million and owns 100% of the Class B membership interests.

Development Projects

Southern Power purchased wind turbine equipment in 2016 and 2017 for deployment to development and construction projects. The significant majority of this equipment either has been deployed to projects that have been completed or has been sold to third parties. Gains on wind turbine equipment contributed to various equity method investments totaled approximately $37 million in 2021. Gains on wind turbine equipment sales were immaterial in 2020 and there were no sales in 2022.

Sale of Plant Mankato

In January 2020, Southern Power completed the sale of its equity interests in Plant Mankato (including the 385-MW expansion unit completed in 2019) to a subsidiary of Xcel Energy Inc. for a purchase price of approximately $663 million, including final working capital adjustments. The sale resulted in a gain of approximately $39 million ($23 million after tax). Plant Mankato represented an individually significant component of Southern Power.

Southern Company Gas

Sale of Sequent

On July 1, 2021, Southern Company Gas affiliates completed the sale of Sequent to Williams Field Services Group for a total cash purchase price of $159 million, including final working capital adjustments. The pre-tax gain associated with the transaction was approximately $121 million ($92 million after tax). The sale resulted in $85 million of additional tax expense

adjustments. The pre-tax gain associated with the transaction was approximately $121 million ($92 million after tax). The sale resulted in $85 million of additional tax expense.

Sale of Pivotal LNG and Atlantic Coast Pipeline

In March 2020, Southern Company Gas completed the sale of its interests in Pivotal LNG and Atlantic Coast Pipeline to Dominion Modular LNG Holdings, Inc. and Dominion Atlantic Coast Pipeline, LLC, respectively, with aggregate proceeds of $178 million, including final working capital adjustments. The loss associated with the transactions was immaterial. In connection with the sale, Southern Company Gas received two additional $5 million payments upon Dominion Modular LNG Holdings, Inc. meeting certain milestones related to Pivotal LNG in April 2021 and May 2022, respectively.

Sale of Natural Gas Storage Facilities

In December 2020, Southern Company Gas completed the sale of Jefferson Island to EnLink Midstream, LLC for a total purchase price of $33 million, including estimated working capital adjustments. The gain associated with the sale totaled $22 million pre-tax ($16 million after tax).

On September 7, 2022, certain affiliates of Southern Company Gas entered into agreements to sell two natural gas storage facilities located in California and Texas for an aggregate purchase price of $186 million, plus working capital and certain other adjustments. The sale of the Texas facility was completed on November 18, 2022. Completion of the sale of the California facility is expected later in 2023 and is subject to certain closing conditions, including, among others, approval from the California Public Utilities Commission without a material burdensome condition. The ultimate outcome of this matter cannot be determined at this time. Completion of the sale of the Texas facility was subject to release of a Southern Company Gas parent guarantee, which was executed on October 20, 2022 and, as a result, Southern Company Gas recorded pre-tax impairment charges totaling approximately $131 million ($99 million after tax) in the fourth quarter 2022.

16. SEGMENT AND RELATED INFORMATION

Southern Company

Southern Company's reportable business segments are the sale of electricity by the traditional electric operating companies, the sale of electricity in the competitive wholesale market by Southern Power, and the sale of natural gas and other complementary products and services by Southern Company Gas. Revenues from sales by Southern Power to the traditional electric operating companies were $875 million, $515 million, and $364 million in 2022, 2021, and 2020, respectively. Revenues from sales of natural gas from Southern Company Gas to the traditional electric operating companies were immaterial for all periods presented. Revenues from sales of natural gas from Southern Company Gas (prior to its sale of Sequent) to Southern Power were $18 million and $26 million in 2021 and 2020, respectively. The "All Other" column includes the Southern Company parent entity, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include providing distributed energy and resilience solutions and deploying microgrids for commercial, industrial, governmental, and utility customers, as well as investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material.

Financial data for business segments and products and services for the years ended December 31, 2022, 2021, and 2020 was as follows:

	Electric Utilities							
	Traditional Electric Operating Companies	Southern Power	Eliminations	Total	Southern Company Gas	All Other	Eliminations	Consolidated
				(in millions)				
2022								
Operating revenues	**$ 20,408**	**$ 3,369**	**$ (904)**	**$ 22,873**	**$ 5,962**	**$ 593**	**$ (149)**	**$ 29,279**
Depreciation and amortization	**2,513**	**516**	**—**	**3,029**	**559**	**75**	**—**	**3,663**
Interest income	**44**	**3**	**—**	**47**	**3**	**16**	**(7)**	**59**
Earnings from equity method investments	**—**	**—**	**—**	**—**	**148**	**3**	**—**	**151**
Interest expense	**929**	**138**	**—**	**1,067**	**263**	**694**	**(2)**	**2,022**
Income taxes (benefit)	**828**	**20**	**—**	**848**	**180**	**(233)**	**—**	**795**
Segment net income (loss)[a][b][c][d]	**3,318**	**354**	**—**	**3,672**	**572**	**(711)**	**(9)**	**3,524**
Goodwill	**—**	**2**	**—**	**2**	**5,015**	**144**	**—**	**5,161**
Total assets	**95,861**	**13,081**	**(659)**	**108,283**	**24,621**	**2,665**	**(678)**	**134,891**
2021								
Operating revenues	$ 16,614	$ 2,216	$ (530)	$ 18,300	$ 4,380	$ 582	$ (149)	$ 23,113
Depreciation and amortization	2,436	517	—	2,953	536	76	—	3,565
Interest income	20	1	—	21	—	4	(3)	22
Earnings from equity method investments	1	—	—	1	50	24	1	76
Interest expense	821	147	—	968	238	631	—	1,837
Income taxes (benefit)	232	(13)	—	219	275	(227)	—	267
Segment net income (loss)[a][b][c][f][g][h]	1,981	266	—	2,247	539	(384)	(9)	2,393
Goodwill	—	2	—	2	5,015	263	—	5,280
Total assets	89,051	13,390	(667)	101,774	23,560	2,975	(775)	127,534
2020								
Operating revenues	$ 15,135	$ 1,733	$ (371)	$ 16,497	$ 3,434	$ 596	$ (152)	$ 20,375
Depreciation and amortization	2,447	494	—	2,941	500	77	—	3,518
Interest income	26	4	—	30	5	6	(4)	37
Earnings from equity method investments	—	—	—	—	141	12	—	153
Interest expense	825	151	—	976	231	614	—	1,821
Income taxes (benefit)	514	3	—	517	173	(297)	—	393
Segment net income (loss)[a][b][h][i][j]	2,877	238	—	3,115	590	(592)	6	3,119
Goodwill	—	2	—	2	5,015	263	—	5,280
Total assets	85,486	13,235	(680)	98,041	22,630	3,168	(904)	122,935

(a) Attributable to Southern Company.

(b) For the traditional electric operating companies, includes pre-tax charges to income at Georgia Power for the estimated probable loss associated with the construction of Plant Vogtle Units 3 and 4 of $183 million ($137 million after tax) in 2022, $1.7 billion ($1.3 billion after tax) in 2021, and $325 million ($242 million after tax) in 2020. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

(c) For Southern Company Gas, includes pre-tax impairment charges totaling approximately $131 million ($99 million after tax) related to the sale of natural gas storage facilities. See Note 15 under "Southern Company Gas" for additional information.

(d) For the "All Other" column, includes a $119 million goodwill impairment loss (pre-tax and after tax) at PowerSecure. See Note 1 under "Goodwill and Other Intangible Assets and Liabilities" for additional information.

(e) For Southern Power, includes gains on wind turbine equipment contributed to various equity method investments totaling approximately $37 million pre-tax ($28 million after tax). See Notes 7 and 15 under "Southern Power" for additional information.

(f) For Southern Company Gas, includes a pre-tax gain of $121 million ($92 million after tax) related to its sale of Sequent, as well as the resulting $85 million of additional tax expense due to changes in state apportionment rates, and pre-tax impairment charges totaling $84 million ($67 million after tax) related to its equity method investment in the PennEast Pipeline project. See Notes 7 and 15 under "Southern Company Gas" for additional information.

(g) For the "All Other" column, includes a pre-tax gain of $93 million ($99 million gain after tax) associated with the termination of two leveraged leases projects. See Note 15 under "Southern Company" for additional information.

(h) For the "All Other" column, includes pre-tax impairment charges totaling $7 million ($6 million after tax) in 2021 and $206 million ($105 million after tax) in 2020 related to leveraged lease investments. See Notes 9 and 15 under "Southern Company Leveraged Lease" and "Southern Company," respectively, for additional information.

(i) For Southern Power, includes a $39 million pre-tax gain ($23 million gain after tax) on the sale of Plant Mankato. See Note 15 under "Southern Power" for additional information.

(j) For Southern Company Gas, includes a $22 million pre-tax gain ($16 million gain after tax) on the sale of Jefferson Island. See Note 15 under "Southern Company Gas" for additional information.

Products and Services

	Electric Utilities' Revenues			
Year	**Retail**	**Wholesale**	**Other**	**Total**
		(in millions)		

		(in millions)		
2022	**$ 18,197**	**$ 3,641**	**$ 1,035**	**$ 22,873**
2021	14,852	2,455	993	18,300
2020	13,643	1,945	909	16,497

Southern Company Gas' Revenues

Year	Gas Distribution Operations	Gas Marketing Services	All Other	Total
		(in millions)		
2022	**$ 5,240**	**$ 638**	**$ 84**	**$ 5,962**
2021	3,656	475	249	4,380
2020	2,902	408	124	3,434

Southern Company Gas

Southern Company Gas manages its business through three reportable segments – gas distribution operations, gas pipeline investments, and gas marketing services. Prior to the sale of Sequent on July 1, 2021, Southern Company Gas' reportable segments also included wholesale gas services. The non-reportable segments are combined and presented as all other. See Note 15 under "Southern Company Gas" for additional information on the disposition activities described herein.

Gas distribution operations is the largest component of Southern Company Gas' business and includes natural gas local distribution utilities that construct, manage, and maintain intrastate natural gas pipelines and gas distribution facilities in four states.

Gas pipeline investments consists of joint ventures in natural gas pipeline investments including a 50% interest in SNG and a 50% joint ownership interest in the Dalton Pipeline. These natural gas pipelines enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. Gas pipeline investments also includes a 20% ownership interest in the PennEast Pipeline project, which was cancelled in September 2021, and through its March 2020 sale, included a 5% ownership interest in the Atlantic Coast Pipeline construction project. See Notes 5 and 7 for additional information.

Through July 1, 2021, wholesale gas services provided natural gas asset management and/or related logistics services for each of Southern Company Gas' utilities except Nicor Gas as well as for non-affiliated companies. Additionally, wholesale gas services engaged in natural gas storage and gas pipeline arbitrage and related activities.

Gas marketing services provides natural gas marketing to end-use customers primarily in Georgia and Illinois through SouthStar.

The all other column includes segments and subsidiaries that fall below the quantitative threshold for separate disclosure, including storage and fuels operations. The all other column included a natural gas storage facility in Texas through its sale on November 18, 2022, Jefferson Island through its sale in December 2020, and Pivotal LNG through its sale in March 2020. See Note 15 to the financial statements under "Southern Company Gas" for additional information, including the sale of a natural gas storage facility in California expected to be completed later in 2023.

Financial data for business segments for the years ended December 31, 2022, 2021, and 2020 was as follows:

	Gas Distribution Operations	Gas Pipeline Investments	Wholesale Gas Services[a]	Gas Marketing Services	Total	All Other	Eliminations	Consolidated
				(in millions)				
2022								
Operating revenues	**$ 5,267**	**$ 32**	**$ —**	**$ 638**	**$ 5,937**	**$ 55**	**$ (30)**	**$ 5,962**
Depreciation and amortization	**516**	**5**	**—**	**16**	**537**	**22**	**—**	**559**
Operating income (loss)	**803**	**21**	**—**	**133**	**957**	**(135)**	**(8)**	**814**
Earnings from equity method investments	**—**	**148**	**—**	**—**	**148**	**—**	**—**	**148**
Interest expense	**229**	**27**	**—**	**3**	**259**	**4**	**—**	**263**
Income taxes (benefit)	**145**	**35**	**—**	**37**	**217**	**(37)**	**—**	**180**
Segment net income (loss)[b]	**470**	**107**	**—**	**94**	**671**	**(99)**	**—**	**572**
Total assets	**22,040**	**1,577**	**—**	**1,616**	**25,233**	**8,943**	**(9,555)**	**24,621**
2021								
Operating revenues	$ 3,679	$ 32	$ 188	$ 475	$ 4,374	$ 38	$ (32)	$ 4,380
Depreciation and amortization	482	5	—	18	505	31	—	536
Operating income (loss)	708	21	241	125	1,095	(40)	—	1,055
Earnings from equity method investments	—	50	—	—	50	—	—	50
Interest expense	207	25	2	3	237	1	—	238
Income taxes (benefit)	120	27	32	34	213	62	—	275
Segment net income (loss)[c][d][e]	412	19	107	88	626	(87)	—	539
Total assets	20,917	1,467	31	1,556	23,971	12,114	(12,525)	23,560
2020								
Operating revenues	$ 2,952	$ 32	$ 74	$ 408	$ 3,466	$ 36	$ (68)	$ 3,434
Depreciation and amortization	442	5	1	22	470	30	—	500
Operating income (loss)	655	20	20	119	814	(7)	5	812
Earnings from equity method investments	—	141	—	—	141	—	—	141
Interest expense	192	29	4	3	228	3	—	231
Income taxes (benefit)	114	33	3	28	178	(5)	—	173
Segment net income (loss)[f]	390	99	14	89	592	(2)	—	590
Total assets	19,090	1,597	850	1,503	23,040	11,336	(11,746)	22,630

(a) As a result of the sale of Sequent, wholesale gas services is no longer a reportable segment in 2022. Prior to the sale of Sequent, the revenues for wholesale gas services were netted with costs associated with its energy and risk management activities. A reconciliation of operating revenues and intercompany revenues is shown in the following table.

	Third Party Gross Revenues	Intercompany Revenues	Total Gross Revenues	Less Gross Gas Costs	Operating Revenues
			(in millions)		
2021	$ 3,881	$ 90	$ 3,971	$ 3,783	$ 188
2020	4,544	115	4,659	4,585	74

(b) For the "All Other" column, includes pre-tax impairment charges totaling approximately $131 million ($99 million after tax) related to the sale of natural gas storage facilities. See Note 15 under "Southern Company Gas" for additional information.

(c) For gas pipeline investments, includes pre-tax impairment charges totaling $84 million ($67 million after tax) related to the equity method investment in the PennEast Pipeline project. See Note 7 under "Southern Company Gas" for additional information.

(d) For wholesale gas services, includes a pre-tax gain of $121 million ($92 million after tax) related to the sale of Sequent.

(e) For the "All Other" column, includes $85 million of additional tax expense as a result of the sale of Sequent.

(f) For the "All Other" column includes a $22 million pre-tax gain ($16 million gain after tax) on the sale of Jefferson Island.

3. CONTINGENCIES, COMMITMENTS, AND GUARANTEES

General Litigation Matters

The Registrants are involved in various matters being litigated and regulatory matters. The ultimate outcome of such pending or potential litigation or regulatory matters against each Registrant and any subsidiaries cannot be determined at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on such Registrant's financial statements.

The Registrants believe the pending legal challenges discussed below have no merit; however, the ultimate outcome of these matters cannot be determined at this time.

Alabama Power

On September 26, 2022, Mobile Baykeeper, through its counsel Southern Environmental Law Center, filed a citizen suit in the U.S. District Court for the Southern District of Alabama alleging that Alabama Power's plan to close the Plant Barry ash pond utilizing a closure-in-place methodology violates the Resource Conservation and Recovery Act (RCRA) and regulations governing CCR. Among other relief requested, Mobile Baykeeper seeks a declaratory judgment that the RCRA and regulations governing CCR are being violated, preliminary and injunctive relief to prevent implementation of Alabama Power's closure plan and the development of a closure plan that satisfies regulations governing CCR requirements. On January 31, 2023, the EPA issued a Notice of Potential Violations associated with Alabama Power's plan to close the Plant Barry ash pond. Alabama Power expects to respond by March 2, 2023, subject to any extension agreed upon by the parties. The ultimate outcome of these matters cannot be determined at this time but could have an impact on Alabama Power's ARO estimates. See Note 6 for a discussion of Alabama Power's ARO liabilities.

Georgia Power

Municipal Franchise Fees

In 2011, plaintiffs filed a putative class action against Georgia Power in the Superior Court of Fulton County, Georgia alleging that Georgia Power's collection in rates of amounts for municipal franchise fees (which fees are paid to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state law claims. This case has been ruled upon and appealed numerous times over the last several years. In 2019, the Georgia PSC issued an order that found Georgia Power has appropriately implemented the municipal franchise fee schedule. In March 2021, the Superior Court of Fulton County granted class certification and Georgia Power's motion for summary judgment and the plaintiffs filed a notice of appeal. In April 2021, Georgia Power filed a notice of cross appeal on the issue of class certification. In December 2021, the Georgia Court of Appeals affirmed the Superior Court's ruling that granted summary judgment to Georgia Power and dismissed Georgia Power's cross appeal on the issue of class certification as moot. Also in December 2021, the plaintiffs filed a petition for writ of certiorari to the Georgia Supreme Court, which was denied on January 27, 2023. On February 6, 2023, the plaintiffs filed a motion for reconsideration with the Georgia Supreme Court. The amount of any possible losses cannot be estimated at this time because, among other factors, it is unknown whether any losses would be subject to recovery from any municipalities.

See Note 17 under "Georgia Power – General Litigation Matters – Municipal Franchise Fees" for additional information.

Plant Scherer

In July 2020, a group of individual plaintiffs filed a complaint, which was amended on December 9, 2022, in the Superior Court of Fulton County, Georgia against Georgia Power alleging that the construction and operation of Plant Scherer has impacted groundwater and air, resulting in alleged personal injuries and property damage. The plaintiffs seek an unspecified amount of monetary damages including punitive damages, a medical monitoring fund, and injunctive relief. Georgia Power has filed multiple motions to dismiss the complaint. On December 29, 2022, the Superior Court of Fulton County, Georgia granted Georgia Power's motion to transfer the case to the Superior Court of Monroe County, Georgia.

In October 2021 and on February 7, 2022, a total of seven additional complaints were filed in the Superior Court of Monroe County, Georgia against Georgia Power alleging that releases from Plant Scherer have impacted groundwater and air, resulting in alleged personal injuries and property damage. The plaintiffs seek an unspecified amount of monetary damages including punitive damages. In November 2021 and March 2022, Georgia Power removed these cases to the U.S. District Court for the Middle District of Georgia. On November 16, 2022, the plaintiffs voluntarily dismissed their complaints without prejudice. Georgia Power anticipates that these plaintiffs will refile their complaints.

On January 9, 2023, an additional complaint was filed in the Superior Court of Monroe County, Georgia against Georgia Power alleging that the construction and operation of Plant Scherer have impacted groundwater and air, resulting in alleged personal injuries. The plaintiff seeks an unspecified amount of monetary damages, including punitive damages. On January 19, 2023, Georgia Power filed a notice to remove the case to the U.S. District Court for the Middle District of Georgia.

The amount of any possible losses from these matters cannot be estimated at this time.

See Note 17 under "Georgia Power – General Litigation Matters – Plant Scherer" for additional information.

Mississippi Power

In 2018, Ray C. Turnage and 10 other individual plaintiffs filed a putative class action complaint against Mississippi Power and the three then-serving members of the Mississippi PSC in the U.S. District Court for the Southern District of Mississippi, which was amended in March 2019 to include four additional plaintiffs. Mississippi Power received Mississippi PSC approval in 2013 to charge a mirror CWIP rate premised upon including in its rate base pre-construction and construction costs for the Kemper IGCC prior to placing the Kemper IGCC into service. The Mississippi Supreme Court reversed that approval and ordered Mississippi Power to refund the amounts paid by customers under the previously-approved mirror CWIP rate. The plaintiffs allege that the initial approval process, and the amount approved, were improper and make claims for gross negligence, reckless conduct, and intentional wrongdoing. They also allege that Mississippi Power underpaid customers by up to $23.5 million in the refund process by applying an incorrect interest rate. The plaintiffs seek to recover, on behalf of themselves and their putative class, actual damages, punitive damages, pre-judgment interest, post-judgment interest, attorney's fees, and costs. The district court dismissed the amended complaint; however, in March 2020, the plaintiffs filed a motion seeking to name the new members of the Mississippi PSC, the Mississippi Development Authority, and Southern Company as additional defendants and add a cause of action against all defendants based on a dormant commerce clause theory under the U.S. Constitution. In July 2020, the plaintiffs filed a motion for leave to file a third amended complaint, which included the same federal claims as the proposed second amended complaint, as well as several additional state law claims based on the allegation that Mississippi Power failed to disclose the annual percentage rate of interest applicable to refunds. In November 2020, the district court denied each of the plaintiffs' pending motions and entered final judgment in favor of Mississippi Power. In January 2021, the district court denied further motions by the plaintiffs to vacate the judgment and to file a revised second amended complaint. In February 2021, the plaintiffs filed a notice of appeal with the U.S. Court of Appeals for the Fifth Circuit. On March 21, 2022, the U.S. Court of Appeals for the Fifth Circuit issued an opinion affirming the dismissal of the claims against the Mississippi PSC defendants but reversing the dismissal of the claims against Mississippi Power. On May 31, 2022, the U.S. Court of Appeals for the Fifth Circuit denied a petition by Mississippi Power for a rehearing en banc and remanded the case to the U.S. District Court for the Southern District of Mississippi for further proceedings. On June 17, 2022, Mississippi Power filed with the trial court a motion to dismiss the complaint. An adverse outcome in this proceeding could have a material impact on Mississippi Power's financial statements.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and the natural gas distribution utilities conduct studies to determine the extent of any required cleanup and have recognized the estimated costs to clean up known impacted sites in the financial statements. A liability for environmental remediation costs is recognized only when a loss is determined to be probable and reasonably estimable and is reduced as expenditures are incurred. The traditional electric operating companies and the natural gas distribution utilities in Illinois and Georgia have each received authority from their respective state

PSCs or other applicable state regulatory agencies to recover approved environmental remediation costs through regulatory mechanisms. Any difference between the liabilities accrued and costs recovered through rates is deferred as a regulatory asset or liability. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies.

Georgia Power has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected. For all years presented, Georgia Power recovered approximately $12 million annually through the ECCR tariff for environmental remediation under the 2019 ARP. Effective January 1, 2023, Georgia Power is recovering $5 million annually through the ECCR tariff under the 2022 ARP.

Southern Company Gas is subject to environmental remediation liabilities associated with 40 former MGP sites in four different states. Southern Company Gas' accrued environmental remediation liability at December 31, 2022 and 2021 was based on the estimated cost of environmental investigation and remediation associated with these sites.

At December 31, 2022 and 2021, the environmental remediation liability and the balance of under recovered environmental remediation costs were reflected in the balance sheets of Southern Company, Georgia Power, and Southern Company Gas as shown in the table below. Alabama Power did not have environmental remediation liabilities at December 31, 2022 or 2021. Mississippi Power did not have environmental remediation liabilities at December 31, 2022 and had an immaterial balance at December 31, 2021.

	Southern Company	Georgia Power	Southern Company Gas
		(in millions)	
December 31, 2022:			
Environmental remediation liability:			
Other current liabilities	$ 65	$ 15	$ 49
Accrued environmental remediation	207	—	207
Under recovered environmental remediation costs:			
Other regulatory assets, current	$ 59	$ 5	$ 54
Other regulatory assets, deferred	235	20	215
December 31, 2021:			
Environmental remediation liability:			
Other current liabilities	$ 69	$ 17	$ 52
Accrued environmental remediation	197	—	197
Under recovered environmental remediation costs:			
Other regulatory assets, current	$ 71	$ 12	$ 59
Other regulatory assets, deferred	231	23	208

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the regulatory treatment for environmental remediation expenses described above, the final disposition of these matters is not expected to have a material impact on the financial statements of the applicable Registrants.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that required the DOE to dispose of spent nuclear fuel generated at Plants Farley, Hatch, and Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, Alabama Power and Georgia Power filed lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley, Hatch, and Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. In 2019, the Court of Federal Claims granted Alabama Power's and Georgia Power's motion for summary judgment on damages not disputed by the U.S. government, awarding those undisputed damages to Alabama Power and Georgia Power. However, those undisputed damages are not collectible until the court enters final judgment on the remaining damages.

In 2017, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government in the Court of Federal Claims for the costs of continuing to store spent nuclear fuel at Plants Farley, Hatch, and Vogtle Units 1 and 2 for the period from January 1, 2015 through December 31, 2017. In 2020, Alabama Power and Georgia Power filed amended complaints in each of the lawsuits adding damages from January 1, 2018 to December 31, 2019 to the claim period.

The outstanding claims for the period January 1, 2011 through December 31, 2019 total $110 million and $132 million for Alabama Power and Georgia Power (based on its ownership interests), respectively. Damages will continue to accumulate until the issue is resolved, the U.S. government disposes of Alabama Power's and Georgia Power's spent nuclear fuel pursuant to its contractual obligations, or alternative storage is otherwise provided. No amounts have been recognized in the financial statements as of December 31, 2022 for any potential recoveries from the pending lawsuits.

The final outcome of these matters cannot be determined at this time. However, Alabama Power and Georgia Power expect to credit any recoveries for the benefit of customers in accordance with direction from their respective PSC; therefore, no material impact on Southern Company's, Alabama Power's, or Georgia Power's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

Nuclear Insurance

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.7 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $450 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $138 million per incident for each licensed reactor it operates but not more than an aggregate of $20 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $275 million and $330 million, respectively, per incident, but not more than an aggregate of $41 million and $49 million, respectively, to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than November 1, 2023. See Note 5 under "Joint Ownership Agreements" for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, both companies have NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses and policies providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted. Alabama Power and Georgia Power each purchase limits based on the projected full cost of replacement power, subject to ownership limitations, and have each elected a 12-week deductible waiting period for each nuclear plant.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Vogtle Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for Alabama Power and Georgia Power as of December 31, 2022 under the NEIL policies would be $51 million and $85 million, respectively.

Claims resulting from terrorist acts and cyber events are covered under both the ANI and NEIL policies (subject to normal policy limits). The maximum aggregate that NEIL will pay for all claims resulting from terrorist acts and cyber events in any 12-month period is $3.2 billion each, plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the applicable company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's, Alabama Power's, and Georgia Power's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

Other Matters

Traditional Electric Operating Companies

In April 2019, Bellsouth Telecommunications d/b/a AT&T Alabama (AT&T) filed a complaint against Alabama Power with the FCC alleging that the pole rental rate AT&T is required to pay pursuant to the parties' joint use agreement is unjust and unreasonable under federal law. The complaint sought a new rate and approximately $87 million in refunds of alleged overpayments for the preceding

six years. In August 2019, the FCC stayed the case in favor of arbitration, which AT&T has not pursued. The ultimate outcome of this matter cannot be determined at this time, but an adverse outcome could have a material impact on the financial statements of Southern Company and Alabama Power. Georgia Power and Mississippi Power have joint use agreements with other AT&T affiliates.

Mississippi Power

Kemper County Energy Facility

In 2020, 2021, and 2022, Mississippi Power recorded charges to income associated with abandonment and related closure costs and ongoing period costs, net of salvage proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. These charges, including related tax impacts, totaled $4 million pre-tax ($3 million after tax) in 2020, $11 million pre-tax ($8 million after tax) in 2021, and $15 million pre-tax ($12 million after tax) in 2022. The pre-tax charges are included in other operations and maintenance expenses on the statements of income.

Dismantlement of the abandoned gasifier-related assets and site restoration activities are expected to be completed by 2026. Additional pre-tax period costs associated with dismantlement and site restoration activities, including related costs for compliance and safety, ARO accretion, and property taxes, net of salvage, are estimated to total approximately $15 million annually through 2025.

Mississippi Power owns the lignite mine located around the Kemper County energy facility site. As a result of the abandonment of the Kemper IGCC, final mine reclamation began in 2018 and was substantially completed in 2020, with monitoring expected to continue through 2028.

As the mining permit holder, Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation, has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. See Note 6 for additional information.

In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper County energy facility through the grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2. In 2016, additional DOE grants in the amount of $137 million were awarded to the Kemper County energy facility. In 2018, Mississippi Power filed with the DOE its request for property closeout certification under the contract related to the $387 million of total grants received. In 2020, Mississippi Power and Southern Company executed an agreement with the DOE completing Mississippi Power's request, which enabled Mississippi Power to proceed with full dismantlement of the abandoned gasifier-related assets and site restoration activities. In connection with the DOE closeout discussions, in 2019, the Civil Division of the Department of Justice informed Southern Company and Mississippi Power of an investigation related to the grants received. The ultimate outcome of this matter cannot be determined at this time; however, it could have a material impact on Southern Company's and Mississippi Power's financial statements.

Plant Daniel

In conjunction with Southern Company's 2019 sale of Gulf Power, NextEra Energy held back $75 million of the purchase price pending Mississippi Power and NextEra Energy negotiating a mutually acceptable revised operating agreement for Plant Daniel. On July 12, 2022, the co-owners executed a revised operating agreement and Southern Company subsequently received the remaining $75 million of the purchase price. The dispatch procedures in the revised operating agreement for the two jointly-owned coal units at Plant Daniel resulted in Mississippi Power designating one of the two units as primary and the other as secondary in lieu of each company separately owning 100% of a single generating unit. Mississippi Power has the option to purchase its co-owner's ownership interest for $1 on January 15, 2024, provided that Mississippi Power exercises the option no later than 120 days prior to that date. The revised operating agreement did not have a material impact on Mississippi Power's financial statements. See Note 2 under "Mississippi Power – Integrated Resource Plan" for additional information on Plant Daniel.

Department of Revenue Audit

On August 31, 2022, the Mississippi Department of Revenue (Mississippi DOR) completed an audit of sales and use taxes paid by Mississippi Power from 2016 to 2019 and entered a final assessment, indicating a total amount due of $28 million, including associated penalties and interest. Mississippi Power does not agree with the audit findings and, on October 27, 2022, filed an administrative appeal with the Mississippi DOR.

On December 6, 2022, the Mississippi PSC approved an accounting order authorizing Mississippi Power to defer the additional taxes and related interest related to the audit to a regulatory asset, excluding amounts associated with the gasifier and other abandoned Kemper IGCC assets. The authority to defer these costs is not a guarantee of recovery. The review and final disposition of the costs recorded to the regulatory asset will be addressed in a future rate proceeding following completion of the tax audit proceedings.

The ultimate outcome of this matter cannot be determined at this time.

Commitments

To supply a portion of the fuel requirements of the Southern Company system's electric generating plants, the Southern Company system has entered into various long-term commitments not recognized on the balance sheets for the procurement and delivery of fossil fuel and, for Alabama Power and Georgia Power, nuclear fuel. The majority of the Registrants' fuel expense for the periods presented was purchased under long-term commitments. Each Registrant expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

Georgia Power has commitments, in the form of capacity purchases, regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. Portions of the capacity payments made to MEAG Power for its Plant Vogtle Units 1 and

2 investment relate to costs in excess of Georgia Power's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity is included in purchased power in Southern Company's statements of income and in purchased power, non-affiliates in Georgia Power's statements of income. Georgia Power's capacity payments related to this commitment totaled $4 million, $6 million, and $5 million in 2022, 2021, and 2020, respectively. At December 31, 2022, Georgia Power's estimated long-term obligations related to this commitment totaled $41 million, consisting of $3 million for 2023, $4 million annually for 2024 and 2025, $2 million annually for 2026 and 2027, and $26 million thereafter.

See Note 9 for information regarding PPAs accounted for as leases.

Southern Company Gas has commitments for pipeline charges, storage capacity, and gas supply, including charges recoverable through natural gas cost recovery mechanisms or, alternatively, billed to marketers selling retail natural gas. Gas supply commitments include amounts for gas commodity purchases associated with Nicor Gas and SouthStar of 34 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2022 and valued at $157 million. Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations. Southern Company Gas' expected future contractual obligations for pipeline charges, storage capacity, and gas supply that are not recognized on the balance sheets at December 31, 2022 were as follows:

	Pipeline Charges, Storage Capacity, and Gas Supply
	(in millions)
2023	$ 637
2024	455
2025	390
2026	212
2027	134
Thereafter	871
Total	$ 2,699

Guarantees

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with each of the traditional electric operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Alabama Power has guaranteed a $100 million principal amount long-term bank loan SEGCO entered into in 2018 and subsequently extended and amended. Georgia Power has agreed to reimburse Alabama Power for the portion of such obligation corresponding to Georgia Power's proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. At December 31, 2022, the capitalization of SEGCO consisted of $80 million of equity and $100 million of long-term debt that matures in November 2024, on which the annual interest

requirement is derived from a variable rate index. In addition, SEGCO had short-term debt outstanding of $17 million. See Note 7 under "SEGCO" for additional information.

As discussed in Note 9, Alabama Power and Georgia Power have entered into certain residual value guarantees related to railcar leases.

17. SUBSEQUENT EVENTS

Georgia Power

Fuel Cost Recovery

On February 28, 2023, Georgia Power filed a request with the Georgia PSC to increase fuel rates by 78% effective June 1, 2023, which is expected to increase annual billings by approximately $1.5 billion. Georgia Power expects to amend the filed request in April 2023 to reflect more recent actual and projected fuel prices, which are currently lower than originally requested. The requested changes in fuel rates have no significant effect on Georgia Power's net income but do impact the related operating cash flows. Georgia Power expects the Georgia PSC to make a final decision on this matter on May 16, 2023. The ultimate outcome of this matter cannot be determined at this time.

See Note 2 under "Georgia Power – Fuel Cost Recovery" for additional information.

Nuclear Construction

Georgia Power filed its twenty-eighth VCM report with the Georgia PSC on February 16, 2023, which reflects the revised capital cost forecast described in Note 2 under "Georgia Power – Nuclear Construction" and $461 million of construction capital costs incurred from July 1, 2022 through December 31, 2022.

On March 6, 2023, Plant Vogtle Unit 3 achieved self-sustaining nuclear fission, commonly referred to as initial criticality, which is a key milestone in the start-up process.

Hot functional testing for Plant Vogtle Unit 4 commenced on March 20, 2023.

See Note 2 under "Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

General Litigation Matters

Municipal Franchise Fees

On February 16, 2023, the Georgia Supreme Court denied the plaintiffs' motion for reconsideration. This matter is now concluded.

See Note 3 under "General Litigation Matters – Georgia Power – Municipal Franchise Fees" for additional information.

Plant Scherer

On February 21, 2023, the plaintiff voluntarily dismissed the complaint that was filed on January 9, 2023. Georgia Power anticipates that this plaintiff will refile the complaint.

See Note 3 under "General Litigation Matters – Georgia Power – Plant Scherer" for additional information.

Nuclear Decommissioning

Following initial criticality on March 6, 2023, Georgia Power recorded AROs of approximately $90 million related to Plant Vogtle Unit 3. See Note 2 under "Georgia Power – Nuclear Construction" and "Nuclear Construction" herein for additional information on construction and start-up of Plant Vogtle Units 3 and 4.

See Note 6 for additional information regarding AROs.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Comp I
1	Balance of Account 219 at Beginning of Preceding Year					(47,172,753)		(47,172,753)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income					6,252,976		6,252,976		
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)					6,252,976		6,252,976	583,872,315	5
5	Balance of Account 219 at End of Preceding Quarter/Year					(40,919,777)		(40,919,777)		
6	Balance of Account 219 at Beginning of Current Year					(40,919,777)		(40,919,777)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income					5,185,289		5,185,289		
8	Current Quarter/Year to Date Changes in Fair Value					23,255,077		23,255,077		
9	Total (lines 7 and 8)					28,440,366		28,440,366	1,813,353,766	1,8
10	Balance of Account 219 at End of Current Quarter/Year				(a) 0	(12,479,411)		(12,479,411)		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossBalance

See Schedules 232 and 278 for gas and electric fair value hedges

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	41,452,976,682	41,452,976,682					
4	Property Under Capital Leases	1,867,822,791	1,867,822,791					
5	Plant Purchased or Sold							
6	Completed Construction not Classified							
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	43,320,799,473	43,320,799,473					
9	Leased to Others							
10	Held for Future Use	106,067,323	106,067,323					
11	Construction Work in Progress	8,120,609,322	8,120,609,322					
12	Acquisition Adjustments	28,251,085	28,251,085					
13	Total Utility Plant (8 thru 12)	51,575,727,203	51,575,727,203					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	13,156,790,331	13,156,790,331					
15	Net Utility Plant (13 less 14)	38,418,936,872	38,418,936,872					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	12,619,134,167	12,619,134,167					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20								

	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	510,204,155	510,204,155					
22	Total in Service (18 thru 21)	13,129,338,322	13,129,338,322					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	27,452,009	27,452,009					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	13,156,790,331	13,156,790,331					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	109,916,958	61,722,621		(b) 60,640,763	110,998,816
3	Nuclear Materials	70,420,712	54,365,883		(c) 41,815,206	82,971,389
4	Allowance for Funds Used during Construction	22,995,282	14,819,636		(d) 2,376,301	35,438,617
5	(Other Overhead Construction Costs, provide details in footnote)	5,709,350	10,264,851		(e) 7,426,162	8,548,039
6	SUBTOTAL (Total 2 thru 5)	209,042,302			112,258,432	237,956,861
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	202,443,033	112,258,433		(f) 89,248,656	225,452,810
9	In Reactor (120.3)	493,957,304	90,951,408		(g) 104,519,989	480,388,723
10	SUBTOTAL (Total 8 & 9)	696,400,337				705,841,533
11	Spent Nuclear Fuel (120.4)	49,294,028	102,817,237		(h) 152,111,265	
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	377,637,311		(a) 37,481,143		340,156,168
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	577,099,356				603,642,226
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					

22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedProvisionForAmortizationOfNuclearFuelAssembliesAmortization

Line 13 - Column D Consists of:		
Amortization Expense	$	(122,215,368)
Original Cost of Assets Retired		161,399,263
Transfer of Retired Fuel Assemblies to 120.4		(1,702,752)
Total	$	37,481,143

(b) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	60,610,601
Reactor Account - 120.3		30,162
Total	$	60,640,763

(c) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	41,815,206
Reactor Account - 120.3		—
Total	$	41,815,206

(d) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	2,376,301
Reactor Account - 120.3		—
Total	$	2,376,301

(e) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	7,471,969
Reactor Account - 120.3		(45,807)
Total	$	7,426,162

(f) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions

Transfers of:		
Completed Assemblies to Reactor Account 120.3	$	89,248,656

(g) Concept: NuclearFuelAssembliesInReactorOtherReductions

Transfers of:		
Completed Burn Assembly to Spent Fuel 120.4	$	104,519,989

(h) Concept: SpentNuclearFuelOtherReductions

Transfers of:		
Retired Assemblies to 120.5	$	153,814,017
Transfer of Retired Fuel Assemblies to 120.3		(1,702,752)
Total	$	152,111,265

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	45,130					45,130
3	(302) Franchise and Consents	40,900,343					40,900,343
4	(303) Miscellaneous Intangible Plant	548,732,936	152,993,545	1,850,210			699,876,271
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	589,678,409	152,993,545	1,850,210			740,821,744
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	48,147,176		8			48,147,168
9	(311) Structures and Improvements	918,117,949	(949,305)	103,567,934			813,600,710
10	(312) Boiler Plant Equipment	6,124,961,485	50,116,476	829,454,817			5,345,623,144
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	610,929,499	4,965,271	80,708,998			535,185,772
13	(315) Accessory Electric Equipment	219,201,180	6,715,681	42,021,551			183,895,310
14		31,178,074	5,000,895	12,437,753			23,741,216

	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production	1,545,813,148	(626,772,626)	8,546,787			910,493,735
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	9,498,348,511	(560,923,608)	1,076,737,848			7,860,687,055
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,095,252					1,095,252
19	(321) Structures and Improvements	1,392,345,408	1,335,286	6,539,970			1,387,140,724
20	(322) Reactor Plant Equipment	2,139,114,622	40,733,501	16,914,133			2,162,933,990
21	(323) Turbogenerator Units	617,152,009	14,673,405	7,740,063			624,085,351
22	(324) Accessory Electric Equipment	533,252,497	8,653,072	1,999,513			539,906,056
23	(325) Misc. Power Plant Equipment	223,704,984	4,730,333	(419,879)			228,855,196
24	(326) Asset Retirement Costs for Nuclear Production	306,216,436	(10,582,443)	100,218			295,533,775
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	5,212,881,208	59,543,154	32,874,018			5,239,550,344
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	36,327,260					36,327,260
28	(331) Structures and Improvements	129,852,052	4,468,860	979,865			133,341,047
29	(332) Reservoirs, Dams, and Waterways	329,754,129	4,107,422	427,364			333,434,187
30	(333) Water Wheels, Turbines, and Generators	282,399,489	11,565,267	126,891			293,837,865
31	(334) Accessory Electric Equipment	47,861,769	5,706,422	388,499			53,179,692
32	(335) Misc. Power Plant Equipment	29,127,894	1,019,912	119,678			30,028,128
33	(336) Roads, Railroads, and Bridges	5,651,425	1,477,894	25,995			7,103,324
34	(337) Asset Retirement Costs for Hydraulic Production	7,642,865	(1,130,206)	1,919			6,510,740
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	868,616,883	27,215,571	2,070,211			893,762,243
36	D. Other Production Plant						
37	(340) Land and Land Rights	37,003,665					37,003,665

38	(341) Structures and Improvements	1,797,141,309	120,421,191	49,669,277			1,867,893,223
39	(342) Fuel Holders, Products, and Accessories	85,294,629	1,352,232	103,941			86,542,920
40	(343) Prime Movers	1,678,840,834	36,277,038	22,376,457			1,692,741,415
41	(344) Generators	1,253,287,938	9,515,928	2,348,746			1,260,455,120
42	(345) Accessory Electric Equipment	151,901,401	3,626,108	2,166,856			153,360,653
43	(346) Misc. Power Plant Equipment	39,125,054	4,634,886	1,043,296			42,716,644
44	(347) Asset Retirement Costs for Other Production	43,089,932	6,898,103				49,988,035
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	5,085,684,762	182,725,486	77,708,573			5,190,701,675
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	20,665,531,364	(291,439,397)	1,189,390,650			19,184,701,317
47	3. Transmission Plant						
48	(350) Land and Land Rights	430,631,233	7,225,363	4,898,513			432,958,083
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	247,386,144	17,674,707	711,955			264,348,896
50	(353) Station Equipment	2,722,009,412	268,473,449	58,721,034			2,931,761,827
51	(354) Towers and Fixtures	1,090,038,289	55,733,358	4,494,223			1,141,277,424
52	(355) Poles and Fixtures	861,039,450	44,616,295	17,532,333			888,123,412
53	(356) Overhead Conductors and Devices	1,699,599,717	132,943,775	51,477,100			1,781,066,392
54	(357) Underground Conduit	11,851,603					11,851,603
55	(358) Underground Conductors and Devices	24,330,726	(1,129,350)	4,174			23,197,202
56	(359) Roads and Trails	11,900,671	2,999,224				14,899,895
57	(359.1) Asset Retirement Costs for Transmission Plant	102,329	(1,009,832)	67			(907,570)
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	7,098,889,574	527,526,989	137,839,399			7,488,577,164
59	4. Distribution Plant						
60	(360) Land and Land Rights	175,763,063	46,568,112				222,331,175
61	(361) Structures and Improvements	260,615,045	26,460,998	270,772			286,805,271

62	(362) Station Equipment	1,795,653,545	166,486,520	(1,086,161)			1,963,226,226
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	1,253,977,613	180,625,933	24,019,929			1,410,583,617
65	(365) Overhead Conductors and Devices	1,510,666,376	172,028,169	11,617,031			1,671,077,514
66	(366) Underground Conduit	511,265,425	82,704,547	3,306,266			590,663,706
67	(367) Underground Conductors and Devices	2,244,448,026	561,105,057	10,093,955			2,795,459,128
68	(368) Line Transformers	1,860,336,085	139,800,642	4,726,432			1,995,410,295
69	(369) Services	1,249,053,445	(7,898,611)	1,319,221			1,239,835,613
70	(370) Meters	543,895,719	27,283,367	24,810,403			546,368,683
71	(371) Installations on Customer Premises	3,106,685	8,725,271	248,810			11,583,146
72	(372) Leased Property on Customer Premises	798,128					798,128
73	(373) Street Lighting and Signal Systems	988,483,161	89,705,670	25,757,785			1,052,431,046
74	(374) Asset Retirement Costs for Distribution Plant	7,761,020	(7,317,386)	7,021			436,613
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	12,405,823,336	1,486,278,289	105,091,464			13,787,010,161
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	34,560,442	127,991	322,095			34,366,338

87	(390) Structures and Improvements	738,152,174	72,155,514	(7,661,176)			817,968,864
88	(391) Office Furniture and Equipment	118,204,082	7,425,720	18,899,119			106,730,683
89	(392) Transportation Equipment	400,488,005	28,989,403	7,699,534			421,777,874
90	(393) Stores Equipment	4,900,282	660,878	1,026,895			4,534,265
91	(394) Tools, Shop and Garage Equipment	71,868,460	18,532,384	6,378,730			84,022,114
92	(395) Laboratory Equipment	66,520,276	9,798,265	9,477,076			66,841,465
93	(396) Power Operated Equipment	31,101,528	3,799,132	853,824			34,046,836
94	(397) Communication Equipment	502,098,993	20,717,033	7,827,755			514,988,271
95	(398) Miscellaneous Equipment	42,079,851	7,712,442	8,236,887			41,555,406
96	SUBTOTAL (Enter Total of lines 86 thru 95)	2,009,974,093	169,918,762	53,060,739			2,126,832,116
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	8,364,131	(15,477,177)	29,983			(7,143,029)
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	2,018,338,224	154,441,585	53,090,722			2,119,689,087
100	TOTAL (Accounts 101 and 106)	42,778,260,907	2,029,801,011	1,487,262,445			43,320,799,473
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	42,778,260,907	2,029,801,011	1,487,262,445			[a]43,320,799,473

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantInService

Plant-in-service balances include the following lease balances:

		Plant in Service
Capital Leases:		
Other Production	$	256,007,409
General		89,317,330
	$	345,324,739
Operating Leases:		
Steam Production	$	36,388,258
Other Production		1,437,316,202
Nuclear Production		584,597
General		48,208,995
	$	1,522,498,052

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
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46						
47	TOTAL					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ 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 Dahlonega 500kv T/L	12/01/2008	12/31/2040	10,543,832
3	New Hampstead Substation	06/30/2009	12/31/2040	53,836
4	S Dahlonega-Clermont Jct 500kv T/L	09/30/2009	12/31/2040	28,188,653
5	S Dahlonega-Clermont Jct 230kv T/L	09/30/2009	12/31/2040	17,268,413
6	Bethabara-E. Walton 230kv T/L Site	03/31/2011	12/31/2040	3,708,308
7	Piedmont Substation Site	03/31/2011	12/31/2040	12,933,362
8	Boyd Ave Substation Site	08/31/2012	12/31/2040	1,334,192
9	Stewart County	09/01/2012	(a) 12/31/2030	22,796,564
10	McDonough-East Point 230 KV	09/01/2014	12/31/2040	89,188
11	Utoy Springs Substation Site	09/01/2014	12/31/2040	594,185
12	Wallace Dam - Klondike 500 KV	09/01/2014	12/31/2031	3,628,989
13	South Hall - Winder T/L	09/01/2014	12/31/2035	883,035
14	Medical Arts Substation Site	02/01/2017	12/31/2026	1,236,065
15	Savannah Portside International- Old River Road Substation Site	08/01/2018	12/31/2040	30,266
16	Northwest Region Operating HQ Site	10/01/2019	12/31/2024	529,886
17	Old Washington Road Substation Site	02/01/2020	12/31/2024	280,159
18	Lewiston Road Substation Site	03/01/2020	12/31/2025	1,968,390
21	Other Property:			
22				
23				
24				
25				
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27				
28				
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47	TOTAL			106,067,323

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

The earliest date this is expected to be in service is 12/31/2030.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Plant Vogtle Units 3&4 Construction	9,772,150,008
2	Plant Bowen - Clean Air Compliance	38,435,070
3	Plant Bowen - Miscellaneous Additions	23,433,359
4	Plant Bowen - Outage Projects	1,153,666
5	Plant Scherer - Outage Projects	1,570,949
6	Plant Yates - Miscellaneous Additions	5,652,288
7	Plant Yates - Service Water Pond Intake	2,297,605
8	Plant Hatch - Controls	20,976,218
9	Plant Hatch - Electrical	15,950,989
10	Plant Hatch - Mechanical	6,170,270
11	Plant Hatch - Miscellaneous Additions	17,047,958
12	Plant Vogtle 1&2 - Controls	7,781,202
13	Plant Vogtle 1&2 - Dry Cask Storage Modifications	1,493,810
14	Plant Vogtle 1&2 - Mechanical	1,514,636
15	Plant Vogtle 1&2 - Miscellaneous Additions	24,239,822
16	Chattahoochee Hydro Miscellaneous Additions	45,100,784
17	North Georgia Hydro Miscellaneous Additions	66,052,510
18	Plant Mcintosh - Outage Projects	9,366,926
19	Plant McIntosh - Miscellaneous Additions	8,086,600
20	Plant McIntosh CT - Miscellaneous Additions	4,281,271
21	Plant McDonough - Miscellaneous Additions	22,738,033
22	Plant McDonough CT - Miscellaneous Additions	1,125,671
23	Plant Wilson CT - Miscellaneous Additions	1,664,637
24	Plant Scherer - Miscellaneous Additions	2,513,435
25	Burton Dam - Miscellaneous Additions	1,299,929
26	Wallace Dam - Miscellaneous Additions	1,233,976
27	Miscellaenous Generation Additions	7,200,192
28	Solar Self Build Projects	14,815,738
29	Distribution New Business	71,126,949

30	Outdoor Lighting Projects	7,698,250
31	Miscellaenous Transmission Line Replacements	46,978,805
32	Miscellaneous Transmission Line Additions & Improvements	19,651,493
33	Miscellaneous Transmission Substation Additions & Improvements	27,598,204
34	Miscellaneous Distribution Line Improvements	5,575,647
35	Miscellaneous Distribution Substation Additions & Improvements	28,575,529
36	Grid Investment	388,810,761
37	Substation Reliability Improvements	101,010,856
38	Distribution Projects Contribution In Aid Of Construction Offset	16,501,094
39	Protective Relay Modernization Project	15,223,996
40	Interconnecting Transmission Line Additions & Improvements	18,290,263
41	Distribution Network Improvements - Miscellaneous	16,777,539
42	Overstressed Or Obsolete Circuit Switcher Replacement	13,105,852
43	Spare Equipment Stock	18,577,455
44	Underground Addition & Improvements	2,295,924
45	Austin Drive - Morrow 115KV Rebuild	5,755,658
46	East Watkinsville - Russell Dam 230KV Rebuild	6,751,631
47	Doraville Balance of Substation Upgrades	29,028,116
48	CBM Monitor Deployment	11,060,638
49	South Dahlonega Substation Build	22,344,299
50	Transmission Line Hwy Change	1,694,014
51	Ferc Relicensing Various Hydro Plants	3,665,524
52	ROW Services Perfection	5,885,653
53	Fiber Optics Spurs Construction	50,596,010
54	Corporate Software Upgrades	23,467,606
55	Customer Service Operations Cyber Security	11,072,429
56	Converged Network Upgrades	9,561,702
57	Enterprise Solutions System Upgrades	82,976,912
58	Building Additions & Improvements	32,538,340
59	Substation Additions & Improvements	3,174,045
60	Hydro Misc Additions & Improvements	1,374,469
61	Capital Maintenance / Asset Management	20,946,598
62	Communications Improvements	2,338,690
63	Generation Software Upgrades	4,826,490
64	Power Delivery Software Upgrades	18,599,925
65	Transmission Commitments	12,676,809
66	Customer Service System (CSS) Upgrades	15,331,459
67	Load Related System Improvements	9,385,300

68	Other General Plant	16,414,092
69	Technology	14,177,026
70	Miscellaneous Minor Projects (Less Than $1 Million)	41,787,543
71	Reserve for Future Capital Spend	(3,259,967,825)
43	Total	8,120,609,322

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	12,496,461,405	12,496,461,405		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,106,480,748	1,106,480,748		
4	(403.1) Depreciation Expense for Asset Retirement Costs	38,776,261	38,776,261		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	24,421,050	24,421,050		
7	Other Clearing Accounts	3,805,221	3,805,221		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	161,621,076	[a]161,621,076		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,335,104,356	1,335,104,356		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(1,485,412,235)	[b](1,485,412,235)		
13	Cost of Removal	(327,617,045)	(327,617,045)		
14	Salvage (Credit)	23,226,326	23,226,326		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(1,789,802,954)	(1,789,802,954)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	577,371,360	[c]577,371,360		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	[d]12,619,134,167	[e]12,619,134,167		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,592,920,053	2,592,920,053		

21	Nuclear Production	2,985,650,369	2,985,650,369		
22	Hydraulic Production-Conventional	251,762,662	251,762,662		
23	Hydraulic Production-Pumped Storage	234,316,789	234,316,789		
24	Other Production	831,174,659	831,174,659		
25	Transmission	1,337,587,101	1,337,587,101		
26	Distribution	3,495,034,087	3,495,034,087		
27	Regional Transmission and Market Operation				
28	General	890,688,447	890,688,447		
29	TOTAL (Enter Total of lines 20 thru 28)	{f}12,619,134,167	{g}12,619,134,167		

FOOTNOTE DATA

(a) Concept: OtherAccounts

Reflects provision of Account 108 related to capital/operating leases not recorded to Account 403

		Depreciation Expense
Capital Leases:		
Other Production	$	12,496,646
General		56,515
	$	12,553,161
Operating Leases:		
Steam Production	$	6,269,534
Nuclear Production		1,879,827
Other Production		132,877,464
General		8,041,090
	$	149,067,915

(b) Concept: BookCostOfRetiredPlant

Variance between Schedule Page 204-207 Line No.:100 Column: d and Schedule Page 219 Line No.: 12 Column: c is due to the exclusion of intangible plant retirements on Page 219 for $1,850,210.

(c) Concept: OtherAdjustmentsToAccumulatedDepreciation

Reflects retired plant net book values moved to FERC 182 Deferred Debits and gain/loss resulting from retirements of operating leases.

(d) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Accumulated depreciation balances include the following lease balances:

		Accumulated Depreciation
Capital Leases:		
Other Production	$	(78,394,287)
General		(61,839,240)
	$	(140,233,527)
Operating Leases:		
Steam Production	$	(21,193,969)
Nuclear Production		(476,492)
Other Production		(476,761,977)
General		(16,943,322)
	$	(515,375,760)

(e) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Accumulated depreciation balances include the following lease balances:

		Accumulated Depreciation
Capital Leases:		
Other Production	$	(78,394,287)
General		(61,839,240)
	$	(140,233,527)
Operating Leases:		
Steam Production	$	(21,193,969)
Nuclear Production		(476,492)
Other Production		(476,761,977)
General		(16,943,322)
	$	(515,375,760)

(f) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Accumulated depreciation balances include the following lease balances:

		Accumulated Depreciation
Capital Leases:		
Other Production	$	(78,394,287)
General		(61,839,240)
	$	(140,233,527)
Operating Leases:		
Steam Production	$	(21,193,969)
Nuclear Production		(476,492)
Other Production		(476,761,977)
General		(16,943,322)
	$	(515,375,760)

(g) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Accumulated depreciation balances include the following lease balances:

		Accumulated Depreciation
Capital Leases:		
Other Production	$	(78,394,287)
General		(61,839,240)
	$	(140,233,527)
Operating Leases:		
Steam Production	$	(21,193,969)
Nuclear Production		(476,492)
Other Production		(476,761,977)
General		(16,943,322)
	$	(515,375,760)

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Southern Electric Generating Co.							
2	Common Stock - 90,000 shares	02/11/1959		9,000,000			9,000,000	
3	Common Stock - 45,000 shares	01/25/1960		4,500,000			4,500,000	
4	Common Stock - 23,000 shares	08/28/1969		2,300,000			2,300,000	
5	Common Stock - 6,000 shares	08/24/1970		600,000			600,000	
6	Equity in Undistributed Earnings			24,511,755	5,433,985	(6,345,982)	23,599,758	
7	Piedmont Forrest Corporation							
8	Common Stock - 100,000 shares	11/17/1977		100,000			100,000	
9	Other Paid-in-Capital							
10	Equity in Undistributed Earnings			16,303,956	826,020		17,129,976	
11	Advances from Parent (open account)			885,265		(773,713)	111,552	
42	Total Cost of Account 123.1 $ 16,611,552		Total	58,200,976	6,260,005	(7,119,695)	57,341,286	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	241,180,197	281,851,393	Electric
2	Fuel Stock Expenses Undistributed (Account 152)		2,315,874	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	439,109,785	430,893,064	Electric
8	Transmission Plant (Estimated)	89,962,996	123,759,934	Electric
9	Distribution Plant (Estimated)	129,083,190	168,633,384	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[a]11,880,754	[b]4,882,775	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	670,036,725	728,169,157	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	412,467	389,375	Electric
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)		(45,306)	
17				
18				
19				
20	TOTAL Materials and Supplies	911,629,389	1,010,364,619	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to Other:

		12/31/2021
First Aid & Safety	$	9,578,328
Stationery & Office Supplies		119,146
Automotive		1,138,774
Construction materials		96,695
Mark numbers		395,193
Other (T&D Accounts)		336,371
In-transit		216,247
	$	11,880,754

(b) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to Other:

		12/31/2022
First Aid & Safety	$	1,605,284
Automotive		1,754,327
In-transit		1,397,929
Construction materials		125,235
	$	4,882,775

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	3,565,987	7,254,800									3,565,987	7,254,800
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	403,661										403,661	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	14,640	15,280									14,640	15,280
19	Other:												
20	Allowances Used												

20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Adjustment												
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	3,955,008	7,239,520									3,955,008	7,239,520
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA	9,066	221									9,066	221
38	Deduct: Returned by EPA	9,066	221									9,066	221
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	235,233										235,233	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	37,582										37,582	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	15,682										15,682	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												

21	Cost of Sales/Transfers:												
22	Adjustment												
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	257,133										257,133	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
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						
48						
49	TOTAL					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	(a) None				
20	Total				
21	**Generation Studies**				
22	(b) None				
39	Total				
40	Grand Total				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfStudyPerformed

Southern Company Services receives up-front payments for studies and operating companies do not record any charges to these accounts. Costs are bore at system level. The only time an operating company would have anything to report on page 231 is when the charges exceed the amount collected and the customer does not reimburse Southern Company. Any study completed by an operating company and is under the OATT should be reported by that operating company on page 231.

(b) Concept: DescriptionOfStudyPerformed

Southern Company Services receives up-front payments for studies and operating companies do not record any charges to these accounts. Costs are bore at system level. The only time an operating company would have anything to report on page 231 is when the charges exceed the amount collected and the customer does not reimburse Southern Company. Any study completed by an operating company and is under the OATT should be reported by that operating company on page 231.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	(a) Vacation Pay Accrued (a)	101,796,196	6,022,107	Various	5,435	107,812,868
2	(b) Deferred Income Taxes (b)	558,688,657	154,011,823	282,283	121,643,689	591,056,791
3	(c) Retiree Benefit Plans (c)	1,002,455,261	9,407,468	228,407.3	105,353,509	906,509,220
4	(d) Generating Plant Outage Costs (d)	34,304,954	41,891,640	407.3	46,472,407	29,724,187
5	(e) Asset Retirement Obligations (e)	4,970,151,923	824,460,950	254,411	975,279,813	4,819,333,060
6	(f) Gas and Electric Hedges (f)	8,067,504	69,219,078	Various	10,595,322	66,691,260
7	(g) Storm Damage (g)	69,378,087	13,452,621	924	57,625,106	25,205,602
8	(h) Environmental Remediation (h)	35,417,100	1,868,576	924	12,218,089	25,067,587
9	(i) Deferred Taxes Medicare Subsidy (i)	4,256,386		407.3	4,256,386	
10	(j) Deferred Plant Retirement Costs (j)	462,261,185	618,795,640	407.3	110,231,579	970,825,246
11	(k) Revenue Erosion (k)	789,385	1,489,605	442	1,010,362	1,268,628
12	(l) Customer Data Usage (l)	238,122	87,637			325,759
13	(m) Software & Cloud Computing (m)	33,041,431	25,914,926			58,956,357
14	(n) Energy Efficiency Improvements (n)	30,880	6,888	908	4,751	33,017
15	(o) Nuclear Decommissioning (o)		7,565,252			7,565,252
44	TOTAL	7,280,877,071	1,774,194,211		1,444,696,448	7,610,374,834

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Earned vacation pay is deferred and recognized only when paid as ordered by the Georgia Public Service Commission (PSC) in Docket No. 3270.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The recovery period for the unprotected deficient accumulated deferred income taxes (DADIT) associated with the remeasurement of deferred income taxes on the construction work in progress for Plant Vogtle Units 3 & 4 as a result of the Tax Cuts and Jobs Act will be determined upon the rate proceedings with Georgia PSC associated with Plant Vogtle Units 3 & 4 being placed into service. The other unprotected DADIT associated with the remeasurement of deferred income taxes was amortized over a three-year period ended December 31, 2022 as ordered by the Georgia PSC in Docket No. 42516. The remaining deferred income taxes are being amortized over the related remaining property lives in accordance with IRS normalization principles which may range up to 57 years.

	Beginning Balance	Amortized to 411.1	Net DR/CR Adj	Ending Balance
Deferred Income Taxes	$ 413,553,699	$ —	$ 32,368,134	$ 445,921,833
Unprotected DADIT NCCR	$ 145,134,958	$ —	$ —	$ 145,134,958

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Retiree benefit plans are recovered through current rates over the average remaining service period as ordered by the Georgia PSC in Docket No. 4565, which may range up to 13 years. The additional employee benefit costs as a result of the change in measurement dates were amortized over 15 years ended December 31, 2022 as ordered by the Georgia PSC in Docket No. 25060.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Nuclear outage costs are deferred and amortized over the respective unit's operating cycle as ordered by the Georgia PSC in Docket No. 4007.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Coal Combustion Residuals (CCR) AROs are recovered through the Environmental Compliance Cost Recovery tariff, with approximately $180 million recovered in 2022 and approximately $160 million, $245 million, and $325 million expected to be recovered in 2023, 2024, and 2025, respectively, with the recovery amount for future years updated through compliance filings. Approximately $17 million annually will be recovered for non-CCR AROs through traditional base tariffs. Other cost of removal obligations and non-CCR AROs are recovered over the related property lives, which may range up to 57 years.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Realized and unrealized losses arising from marked to market gas and electric hedges are deferred and recovered when settled as ordered by the Georgia PSC in Docket No. 16134. The Company's natural gas hedging program uses an array of derivative instruments within a 36-month time horizon, as ordered by the Georgia PSC in Docket No. 43011.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The Company accrued $213 million annually during the three-year period ended December 31, 2022, as ordered by the Georgia PSC in Docket No. 42516, to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which are recoverable through base rates. During the second quarter 2022, the Company's regulatory asset for storm damage was eliminated and storm damages are reserved in FERC account 228.1. Effective January 1, 2023, the Company is accruing $31 million annually through December 31, 2025, as ordered by the Georgia PSC in Docket No. 44280. In accordance with the Georgia PSC order in Docket No. 42516, the Company deferred incremental bad debt and other incremental costs in certain identified cost categories that were incurred as result of the COVID-19 pandemic. At December 31, 2022, the incremental costs deferred totaled approximately $25 million. Effective January 1, 2023 the company is amortizing these costs over a three-year period ending December 31, 2025, as ordered by the Georgia PSC in Docket No. 44280.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The Company accrued $12 million annually during the three-year period ended December 31, 2022, as ordered by the Georgia PSC in Docket No. 42516, to cover the costs of environmental remediation. Effective January 1, 2023, the Company is accruing $5 million annually through December 31, 2025, as ordered by the Georgia PSC in Docket No. 44280.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferred taxes medicare subsidy were recovered and amortized over a 12-year period ending December 31, 2022 as ordered by the Georgia PSC in Docket No. 31958.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC orders in Docket Nos. 34218, 36498, 40161, 42310 and 44160, deferred plant retirement costs, including cancelled environmental construction projects, remaining net book values, and unusable materials and supplies inventories, are classified as a regulatory asset. The cancelled environmental construction projects were amortized over a nine-year period ending December 31, 2022. The remaining net book values of Plant Branch Units 2-4 and Plant Hammond Units 1-4 are being amortized over a period equal to the units' remaining useful lives as approved by the Georgia PSC in Docket Nos. 31958 and 36989, respectively. The remaining net book values of Plant Mitchell Unit 3, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 were amortized over a three-year period ending December 31, 2022 as approved by the Georgia PSC in Docket No. 42516. The remaining net book values of Plant Wansley Units 1-2 and CT Unit 5A were amortized at a rate equal to the unit depreciation rates approved by the Georgia PSC in Docket No. 42516 through December 31, 2022. Effective January 1, 2023, the remaining net book value of Plant Wansley Units 1-2 is amortized over a period equal to the units' remaining useful lives as approved by the Georgia PSC in Docket No. 42516 and the remaining net book value of Plant Wansley CT Unit 5A is amortized over a three-year period ending December 31, 2025 as ordered by the Georgia PSC in Docket No. 44280. The decision on the timing of the recovery of the unusable materials and supplies inventories will be deferred until a future base rate case.

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket No. 44280, any revenue erosion resulting from the conversion of additional customers to a specific time-of-use rate will be deferred and recovered from customers in 2023 through 2025 through the annual compliance filings.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket No. 44280, costs associated with investigation and implementation of providing hourly usage information to all metered customers will be recovered over a three-year period ending December 31, 2025.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Effective January 1, 2023, certain implementation costs related to software and cloud computing projects incurred through 2022 were deferred and will be amortized over a five-year period ending December 31, 2027 in accordance with the Georgia PSC order in Docket 44280. The recovery of future deferred costs will be determined by the Georgia PSC in the next base rate.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket Nos. 42310 and 42311, the costs of energy efficient upgrades, prepaid by the Company, for participating customers associated with

the Income Qualified Tariff Based Energy Efficiency Pilot, or RISE pilot, are deferred and recovered from those customers over the life of the installed equipment not to exceed ten years.
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
In accordance with the Nuclear Regulatory Commission requirement to satisfy funding assurance for nuclear decommissioning, the Company provided funding to the external nuclear decommissioning trust. The recovery of the nuclear decommissioning trust funding will be determined by the Georgia PSC in future regulatory proceedings.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Jobs in Progress - Cost	15,727,286	25,810,339	143	38,070,855	3,466,770
2	Joint Owner Other Deferred Billings	12,752,352	14,247,828	902-926, 143	21,476,722	5,523,458
3	Funding Collateral	509,356				509,356
4	Progress Payments	36,938,290	135,227,558	107, 120.4, 154	129,585,932	42,579,916
5	Non Current Fuel Cost Recovery	410,036,834	1,661,012,929	440, 442, 444, 446	14,956,194	2,056,093,569
6	[a] Cash Surrender Value Insurance (a)	6,480,492	320,815	426.2	27,807	6,773,500
7	Disputed Payments	2,970,501	3,529,499	232, 107	6,500,000	
8	Deferred Capitalized Interest on Nuclear Fuel During Construction	35,733,838	3,704,079			39,437,917
9	Miscellaneous Deferred Debits	1,914,603	162,500	Various	407,476	1,669,627
10	Other Post-Retirement Benefits and Pension-Associated Co	179,382,615	6,321,781	234	517,815	185,186,581
11	GPC Vogtle 3&4 Construction Payments	31,859,697	1,908,624,279	107, 143	1,921,713,974	18,770,002
12	[b] Credit Line Fees (b)	5,242,616	100,820	431	1,310,654	4,032,782
13	[c] Transmission Solar Interconnection (c)	4,586,187	5,795,984	555	839,139	9,543,032
14	Pooled Equipment Inventory Operating Fund Deposit	65,196				65,196
15	Mobile Device Billing		7,576	184, 232, 426.5,511, 524, 539, 549, 921	3,427	4,149
16	[d] Sales Commissions (d)	3,486,286	16,783,703	416, 912	15,188,469	5,081,520
17				—		
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	747,686,149				2,378,737,375

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfMiscellaneousDeferredDebits

Cash Surrender Value Insurance is amortized over a 12-month period.

(b) Concept: DescriptionOfMiscellaneousDeferredDebits

Credit line fees are amortized over the term of the related credit facility.

(c) Concept: DescriptionOfMiscellaneousDeferredDebits

Transmission Solar Interconnection reimbursements are being amortized over 20 or 30 years depending on the terms of the purchase power agreement starting in April 2017.

(d) Concept: DescriptionOfMiscellaneousDeferredDebits

Sales commissions are amortized over the term of the sales contracts which range from 2 to 3 years.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2		1,397,494,309	1,375,977,052
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,397,494,309	1,375,977,052
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	199,823,648	119,499,441
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	(a) 1,597,317,957	1,495,476,493

Notes

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

ACCUMULATED DEFERRED INCOME TAXES (ACCOUNT 190)	BALANCE AT BEG OF YEAR	BALANCE AT END OF YEAR
Accrual for Uncollectibles	$ 415,433	$ 645,749
Accumulated Rate Refund Georgia Public Service Commission	1,806,427	30,824,146
Affirmative Adjustments*	-	8,478,950
Capacity Buybacks*	56,038	7,630
Capitalized Purchase Power Agreement Southern Power Co	9,576,608	8,472,722
Deferred Revenues - Electric	183,066	54,237
Demand Side Management Recovery	14,947,457	9,580,081
FAS 133 Mark to Market*	7,269,519	7,763,311
GA Rate Change Reserve Gross Up	867,287	-
Health Reimbursement Accrual	513,722	587,397
Income Taxes Deferred - Electric	212,973,444	243,576,200
Protected Gross Up EADIT	568,818,102	552,719,580
Income Taxes Deferred - CWIP Electric	(15,810,215)	(18,292,275)
Income Taxes Deferred - Non Electric*	2,342,190	3,070,827
Income Taxes Deferred - CWIP Non Electric*	(36,772,655)	(39,575,884)
Injuries & Damages Reserve	1,397,696	3,862,585
Nuclear Construction Cost Recovery Over/Under Recovery	3,962,448	-
Other Comprehensive Income - Hedge Settlement	13,785,008	4,064,883
Other Basis Differences	84,270,634	74,181,501
Accrued Liabilities - Electric	112,814,670	110,588,151
Accrued Liabilities - Non Electric*	28,789,974	15,461,181
Storm Damage	-	22,214,683
Tax Credit Carry Forward - Electric	345,119,713	346,558,564
Tax Credit Carry Forward - Non Electric*	198,138,582	124,293,426
Unbilled Fuel Revenues	23,822,210	23,051,473
Unprotected Gross Up EADIT	54,743,224	-
Unprotected Gross Up Deficient EADIT NCCR	(36,712,625)	(36,712,625)
Total	$ 1,597,317,957	$ 1,495,476,493
*Other Income and Deductions		
Classification of Totals:		
Federal Income Tax	$ 924,508,257	$ 882,849,107
State Income Tax	$ 672,809,700	$ 612,627,386

** Resubmission - update to include this footnote

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock (No Par)	20,000,000			9,261,500	398,473,175				
6	Total	20,000,000			9,261,500	398,473,175				
7	Preferred Stock (Account 204)									
8	Cumulative Preferred, Par Value $100 Per Share	5,000,000	100.00							
9	Non-Cumulative, Par Value $25 Per Share	50,000,000	25.00							
10	Non-Cumulative, Par Value $100 Per Share	15,000,000	100.00							
20	Total	70,000,000								
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2		20,000,000			9,261,500	398,473,175				

	Common Stock (Account 201)									
3	Preferred Stock (Account 204)	70,000,000								
4	Total	90,000,000			9,261,500	398,473,175				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2023-04-20	Year/Period of Report End of: 2022/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	14,143,642,821
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
15.2	Contributions to capital by parent company	1,470,616,486
15.3	Miscellaneous contributions to capital	2,189,134
16	Ending Balance Amount	15,616,448,441
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	15,616,448,441

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
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11		
12		
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17		
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19		
20		
21		
22	TOTAL	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances fr Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZAT PERIOD D From (j)
1	Bonds (Account 221)									
2	Bartow 2nd Series 2009	—	100,000,000							
3	Floyd 1st Series 2009	—	29,000,000							
4	Subtotal		129,000,000							
5	Reacquired Bonds (Account 222)									
6	Bartow 2nd Series 2009	—	(100,000,000)							
7	Floyd 1st Series 2009	—	(29,000,000)							
8	Monroe 1st Series 2012	—	(48,720,000)							
9	Monroe 2nd Series 2006	—	(28,065,000)							
10	Monroe 1st Series 2013	—	(17,500,000)							
11	Burke 1st Series 1996	—	(46,000,000)							
12	Monroe 2nd Series 2009	—	(89,200,000)							
13	Subtotal		(358,485,000)							
14										

	Advances from Associated Companies (Account 223)									
15										
16										
17										
18	Subtotal									
19	Other Long Term Debt (Account 224)									
20	Series N, 5.750%	—	100,000,000		1,040,825			04/15/2003	04/15/2023	04/01/200
21	Series 2007 A, 5.65%	—	250,000,000		1,780,008		856,478	03/13/2007	03/01/2037	04/01/200
22	Series 2007 D, 6.375%	—	(b) 300,000,000					07/17/2007	07/15/2047	07/01/200
23	Series 2009A, 5.95%	—	500,000,000		2,679,965		1,020,706	02/10/2009	02/01/2039	02/01/200
24	Series 2010B, 5.4%	—	600,000,000		3,385,341		2,335,496	06/03/2010	06/01/2040	06/01/201
25	Series 2010C, 4.75%	—	500,000,000		4,533,506		4,820,000	08/31/2010	09/01/2040	08/01/201
26	Series 2012A, 4.30%	—	1,100,000,000		10,792,848	4,228,165	383,702	03/06/2012	03/15/2042	03/01/201
27	Series 2012B, 2.85%	—	400,000,000					05/11/2012	05/15/2022	05/01/201
28	Series 2013A, 4.3%	—	400,000,000		3,884,160		2,604,020	03/15/2013	03/15/2043	03/01/201
29	Series 2016A, 3.25%	—	325,000,000		2,337,915		1,222,000	03/08/2016	04/01/2026	03/01/201
30	Series 2017B, 3.25%	—	400,000,000		2,876,271		452,000	03/03/2017	03/30/2027	03/01/201
31	Series 2019A, 2.20%	—	400,000,000		2,758,160		320,000	09/10/2019	09/15/2024	09/01/201
32	Series 2019B, 2.65%	—	650,000,000		4,769,103		4,882,500	09/10/2019	09/15/2029	09/01/201
33	Series 2020A, 2.10%	—	700,000,000		2,931,354		147,000	01/10/2020	07/30/2023	01/01/202
34	Series 2020B, 3.70%	—	500,000,000		4,707,331		1,630,000	01/10/2020	01/30/2050	01/01/202
35	Series 2021A, 3.25%	—	750,000,000		7,142,232		1,630,000	02/26/2021	03/15/2051	02/26/202
36	Series 2022A, 4.70%	—	700,000,000		5,057,712		2,226,000	05/04/2022	05/15/2032	05/04/202
37	Series 2022B, 5.125%	—	800,000,000		7,426,647		5,840,000	05/04/2022	05/15/2052	05/04/202
38	Heard 1st Series 1996 - Variable	—	3,800,000		281,716			09/01/1996	09/01/2026	09/01/199
39		—	10,080,000		234,522			09/01/1996	09/01/2026	09/01/199

	Floyd 1st Series 1996 - Variable									
40	Burke 1st Series 1996 - Variable	—	46,000,000		1,114,193			09/01/1996	10/01/2032	09/01/199
41	Monroe 1st Series 1997 - Variable	—	19,600,000		719,734			04/01/1997	04/01/2032	04/01/199
42	Appling 1st Series 1997 - Variable	—	18,500,000		863,498			09/01/1997	09/01/2029	09/01/199
43	Heard 1st Series 1997 - Variable	—	33,700,000		800,281			09/01/1997	09/01/2029	09/01/199
44	Bartow 1st Series 1997 - 1.80%	—	38,000,000		1,827,936			09/01/1997	09/01/2029	09/01/199
45	Burke 2nd Series 1994 - 2.25%	—	10,000,000		275,986			01/01/1994	10/01/2032	01/01/199
46	Burke 4th Series 1994 - 2.25%	—	55,000,000		919,195			01/01/1994	10/01/2032	01/01/199
47	Burke 5th Series 1994 - 2.15%	—	55,000,000		1,599,536			01/01/1994	10/01/2032	01/01/199
48	Burke 9th Series 1994 - 2.25%	—	20,000,000		425,804			01/01/1994	10/01/2032	01/01/199
49	Monroe 1st Series 1995 - 2.25%	—	45,000,000		1,543,239			07/01/1995	07/01/2025	07/01/199
50	Burke 4th Series 1995 - 2.25%	—	30,000,000		546,739			09/01/1995	10/01/2032	09/01/199
51	Burke 5th Series 1995 - 2.20%	—	27,000,000		1,398,809			09/01/1995	09/01/2032	09/01/199
52	Coweta 1st Series 2006 - Variable	—	10,125,000		371,668			06/28/2006	06/01/2032	06/28/200
53	Effingham 1st Series 2003 - Variable	—	13,870,000		435,117			02/19/2003	02/01/2038	02/19/200
54	Monroe 2nd Series 2006 - Variable	—	28,065,000		1,464,283			12/13/2006	12/01/2041	12/13/200
55	Heard 1st Series 2007 - Variable	—	17,800,000		403,140			12/06/2007	12/01/2037	12/06/200
56	Floyd 1st Series 2010 - Variable	—	[a]53,000,000					06/26/2008	07/01/2022	06/26/200
57	Burke 1st Series 2008 - Variable	—	68,535,000		1,902,711			11/25/2008	11/01/2048	11/25/200
58		—	65,000,000		1,570,472			11/25/2008	11/01/2048	11/25/200

	Burke 2nd Series 2008 - 2.93%									
59	Monroe 1st Series 2008 - Variable	—	83,515,000		1,509,886			11/25/2008	11/01/2048	11/25/200
60	Monroe 1st Series 2009 - 1.00%	—	40,000,000		1,428,520			07/14/2009	07/01/2049	07/14/200
61	Burke 1st Series 2009 - Variable	—	114,310,000		1,573,880			07/14/2009	07/01/2049	07/14/200
62	Monroe 2nd Series 2009 - Variable	—	89,200,000		1,386,651			09/17/2009	10/01/2048	09/17/200
63	Bartow 1st Series 2009 - 2.75%	—	173,000,000		3,580,633			09/17/2009	12/01/2032	09/17/200
64	Appling First Series 2011 - Variable	—	67,000,000		1,127,321			09/01/2011	09/01/2041	09/01/201
65	Monroe 1st Series 2012 - Variable	—	48,720,000		1,608,423			05/01/2012	06/01/2042	05/01/201
66	Burke 1st Series 2012 - 2.88%	—	85,000,000		2,617,273			06/01/2012	12/01/2049	06/01/201
67	Burke 2nd Series 2012 - 1.70%	—	100,000,000		3,194,933			06/01/2012	12/01/2049	06/01/201
68	Burke 3rd Series 2012 - Variable	—	50,000,000		2,657,911			11/01/2012	11/01/2052	11/01/201
69	Burke 1st Series 2013 - 2.93%	—	104,600,000		6,446,122			11/08/2013	11/01/2053	11/01/201
70	Monroe 1st Series 2013 - Variable	—	17,500,000		1,471,776			03/21/2013	04/01/2043	03/21/201
71	Bartow 1st Series 2013 - 2.88%	—	71,735,000		1,291,583			08/23/2013	08/01/2043	08/23/201
72	Burke 1st Series 2018 - Variable	—	108,155,000		929,925			12/05/2018	11/01/2052	12/05/201
73	Bartow 1st Series 2022 - Variable	—	100,000,000		303,851			11/04/2022	11/01/2062	11/04/202
74	Bartow 2nd Series 2022 - Variable	—	100,000,000		182,696			11/04/2022	11/01/2062	11/04/202
75	Series 2017A 5.00%	—	270,000,000		7,564,746			09/21/2017	10/01/2077	09/01/201
76	[a] DOE Loan 3.860%, 2044	—	200,000,000		[a] 65,433,621			02/20/2014	02/20/2044	
77	DOE Loan 3.488%, 2044	—	500,000,000					02/20/2014	02/20/2044	02/20/201

78	DOE Loan 3.002%, 2044	—	500,000,000					12/11/2014	02/20/2044	
79	DOE Loan 3.283%, 2044	—	600,000,000					06/12/2015	02/20/2044	
80	DOE Loan 3.072%, 2044	—	400,000,000					12/09/2015	02/20/2044	
81	DOE Loan 2.571%, 2044	—	300,000,000					06/08/2016	02/20/2044	
82	DOE Loan 3.142%, 2044	—	125,000,000					12/08/2016	02/20/2044	
83	DOE Loan 3.213%, 2044	—	835,000,000					03/15/2019	02/20/2044	
84	DOE Loan 2.537%, 2044	—	2,409,117					12/20/2019	02/20/2044	
85	DOE Loan 2.537%, 2044 2	—	380,590,883		12,185,988			12/20/2019	02/20/2044	12/20/201
86	DOE Loan 1.652% 2044	—	519,000,000					06/05/2020	02/20/2044	
87	DOE Loan 1.737% 2044	—	329,000,000					12/10/2020	02/20/2044	
88	DOE Loan 2.434% 2044	—	371,000,000					06/24/2021	02/20/2044	
89	DOE Loan 2.178% 2044	—	68,632,896					12/10/2021	02/20/2044	
90	CIBC	—	(d) 125,000,000					07/06/2019	06/09/2022	07/06/201
91	Subtotal		16,921,442,896		203,297,696	4,228,165	30,369,902			
33	TOTAL		16,691,957,896							

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

In 2022, the following DOE Loan principal payments were made:

DOE Loan 3.860%, 2044	$	8,340,000
DOE Loan 3.488%, 2044		8,340,000
DOE Loan 3.002%, 2044		3,336,000
DOE Loan 3.283%, 2044		10,008,000
DOE Loan 3.072%, 2044		6,672,000
DOE Loan 2.571%, 2044		5,004,000
DOE Loan 3.142%, 2044		2,085,000
DOE Loan 3.213%, 2044		13,927,800
DOE Loan 2.537%, 2044		40,184
DOE Loan 2.537%, 2044		6,348,256
DOE Loan 1.652% 2044		8,656,920
DOE Loan 1.737% 2044		5,487,720
DOE Loan 2.434% 2044		6,188,280
DOE Loan 2.178% 2044		3,434,390
	$	87,868,550

(b) Concept: OtherLongTermDebtPrincipalAmountIssued

Amortization of gain on cash flow hedge on Series 2007D Senior Note, which was redeemed in July 2012, is being credited to FERC account 427 through June 2037.

(c) Concept: OtherLongTermDebtPrincipalAmountIssued

In 2022, the following pollution control revenue bonds (PCBs) were issued:

November 2022 - Bartow 1st Series 2022 - $100,000,000 - due November 2062
November 2022 - Bartow 2nd Series 2022 - $100,000,000 - due November 2062

In 2022, the following PCBs were repaid at maturity:

July 2022 - Floyd 1st Series 2010 $53,000,000

(d) Concept: OtherLongTermDebtPrincipalAmountIssued

In 2022, the following bank loan was repaid early:

May 2022 - CBIC - $125,000,000 - due June 2022

(e) Concept: OtherLongTermDebtIssuanceExpense

The $65,433,621 and $12,185,988 in issuance expenses on lines 76 and 85, respectively, are related to all DOE Loan draws.

(f) Concept: InterestExpenseOtherLongTermDebt

Amortization of gain on cash flow hedge on Series 2007D Senior Note, which was redeemed in July 2012, is being credited to FERC account 427 through June 2037.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	1,813,353,766
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See Attachment 261.1	(a) 62,017,586
9	Deductions Recorded on Books Not Deducted for Return	
10	See Attachment 261.1	(b) 1,162,929,120
14	Income Recorded on Books Not Included in Return	
15	See Attachment 261.1	(c) 1,912,618,200
19	Deductions on Return Not Charged Against Book Income	
20	See Attachment 261.1	(d) 750,553,050
27	Federal Tax Net Income	375,129,222
28	Show Computation of Tax:	
29	Federal Income Tax @ 21%	78,777,137
30	Federal Tax Credits	(40,536,221)
31	Tax Reserve	(210,882)
32	Total Income Tax Payable	38,030,034

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TaxableIncomeNotReportedOnBooks

TAXABLE INCOME NOT ON THE BOOKS

Financial Accounting Standards Board Statement No. 133 - Mark to Market	$	1,938,590
Customer Advances for Construction		36,354,788
State Income Tax Payable		20,572,746
Other		3,151,462
TOTAL	**$**	**62,017,586**

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON TAX RETURN

Federal Income Tax	$	189,719,782
State Income Tax		179,875,076
Medicare Subsidy Tax Legislation		4,256,385
Storm Damage Reserve		152,702,802
Premium on Reacquired Debt (Loss)		17,789,391
Non Deductible Depreciation		67,313,506
Municipal Gross Receipts Tax		12,352,002
Retail Sharing		113,921,415
50% Meals & Entertainment Expense		8,982,753
Nuclear Outage		4,580,767
Environmental Remediation Reserve		10,349,515
Transmission Parity Accrual		5,712,122
Vogtle Probable Loss		235,890,717
Bad Debt Reserve		904,204
Severance Pay Plan		1,520,860
Injuries and Damages Reserve		9,676,974
Donations (Fair Market Value over Book)		44,390
Expenditures Not Deductible Section 162/274		21,446,377
Regulatory Retired Units		74,316,602
Other Deferred Costs		1,608,616
Depreciation Related Timing Differences		49,964,864
TOTAL	**$**	**1,162,929,120**

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME ON BOOKS NOT INCLUDED IN RETURN

Allowance for Funds Used During Construction - Equity	$	156,412,191
Amortization of Investment Tax Credit		8,938,554
Demand Side Management Over/Under Recovery		21,071,922
Equity in Earnings of Subs/Partnerships (SEGCO)		5,433,985
Unbilled Fuel Revenues		3,025,859
Deferred Revenue & Expense		817,561
Nuclear Construction Cost Recovery		64,590,348
Fuel Clause Over/Under Recovery		1,646,056,735
Prepaid Rental Income		5,238,050
Other		1,032,995
TOTAL	**$**	**1,912,618,200**

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS NOT CHARGED AGAINST BOOK INCOME

Payroll Tax Deferral - Cares ACT	$	13,632,199
Other Post Retirement Benefits		30,854,699
Deferred Interest on Nuclear Fuel V3&4		3,704,079
Regulatory Asset Cloud Computing		25,914,926
Administrative & General Accruals		27,318,928
Deferred Compensation Board of Directors		1,413,129
Other Post Employment Benefit FAS # 112		2,736,949
Capitalized Purchase Power Agreement Southern Power Company		4,333,777
Regulatory Asset Wansley 1-2		458,901,414
Regulatory Asset COVID19 Costs		25,205,602
Regulatory Asset TOU MB REVENUE Erosion		1,268,628
Stock Based Compensation		28,075,649
Pension		106,468,506
Other		20,724,565
TOTAL	**$**	**750,553,050**

CONSOLIDATION AND ALLOCATION INFORMATION

Members of Group and Tax Allocation (Note 1)

Alabama Power Company	$	51,840,558
Alabama Property Company		2,512,376
Align		(315,000)
Aladyn		—
Georgia Power Company		38,030,034
Piedmont-Forrest Corporation		205,549
Mississippi Power Company		42,028,570
Southern Company Gas		122,448,828
Southern Electric Generating Company		3,157,318
Southern Linc		7,179,754
Southern Nuclear		392,034
Southern		(193,881,663)
So Holdings		(1,417,629)
SPS Holdings		(17,659,910)
So Power		(42,725,877)
Eliminations		(2,222,384)
Total Consolidation and Allocation Information	**$**	**9,572,558**

Note 1: Basis of Allocation: The consolidated federal income tax is allocated under Section 1552 (a) (1) of the Internal Revenue Code of 1986 as prescribed by Rule 45 (c) of the Securities and Exchange Commission's regulations with certain modifications approved by the Securities and Exchange Commission.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts durin been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amou
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifyin
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmit
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertain Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the ta
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT EN YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Pre Ta (Inc Acc 1
1	(a) Property Tax - 2021 & Prior	Property Tax	Georgia		94,465,220	0	0	82,818,133	(2,745,758)	8,901,329	
2	Property Tax - 2022	Property Tax	Georgia		0	1,005,618	292,029,274	100,089,531	1,417,661	192,351,786	
3	Property Tax - 2023	Property Tax	Georgia		0	0	0	1,415,915	0	0	1,4
4	Property Tax - 2021 & Prior	Property Tax	Alabama		0	0	0	0	0	0	
5	Property Tax - 2022	Property Tax	Alabama		0	0	2,473,365	2,473,365	0	0	
6	Property Tax - 2021 & Prior	Property Tax	Mississippi								
7	Property Tax - 2022	Property Tax	Mississippi		0	0	260,000	118,073	0	141,927	
8	Property Tax - 2021 & Prior	Property Tax	South Carolina		613	0	0	631	0	(18)	
9	Property Tax - 2022	Property Tax	South Carolina		0	0	91,125	90,531	0	594	
10	Property Tax - 2021 & Prior	Property Tax	Tennessee		18	0	0	0	0	18	
11	Property Tax - 2022	Property Tax	Tennessee		0	0	11	11	0	0	
12	**Subtotal Property Tax**				94,465,851	1,005,618	294,853,775	187,006,190	(1,328,097)	201,395,636	1,4
13					2,343,164	0	824,417	4,869,498	1,875,485	173,568	

	Federal Income Taxes 2021 & Prior	Income Tax									
14	Federal Income Taxes 2022	Income Tax			0	0	37,205,617	31,216,187	8,884,304	14,873,734	
15	State Income Tax	Income Tax	Georgia		3,277,563	0	(19,404,128)	(5,368,894)	(1,214,002)	7,801	11,9
16	**Subtotal Income Tax**				5,620,727	0	18,625,906	30,716,791	9,545,787	15,055,103	11,9
17	Franchise Fees - 2021	Franchise Tax	Georgia		208,291,324	0	0	195,550,579	0	12,740,745	
18	Franchise Fees - 2022	Franchise Tax	Georgia		0	0	264,151,113	0	0	264,151,113	
19	**Subtotal Franchise Tax**				208,291,324	0	264,151,113	195,550,579	0	276,891,858	
20	Net Worth	Other License And Fees Tax	Georgia		0	0	5,000	5,000	0	0	
21	Business License	Other License And Fees Tax	Alabama		0	0	9,000	9,000	0	0	
22	Business License	Other License And Fees Tax	Mississippi		0	0	21,618	21,618	0	0	
23	**Subtotal Other License And Fees Tax**				0	0	35,618	35,618	0	0	
24	FUTA	Payroll Tax	—		0	0	311,058	311,058	0	0	
25	SUTA	Payroll Tax	Georgia		0	0	226,717	226,717	0	0	
26	SUTA	Payroll Tax	Alabama		0	0	1,674	1,674	0	0	
27	FICA	Payroll Tax	—		12,749,721	0	0	(1,475,690)	0	14,225,411	
28	FICA-COVID 19 Federal	Payroll Tax	—								
29	FICA-COVID 19 State	Payroll Tax	—		13,632,199	0	(13,632,199)	0	0	0	
30	**Subtotal Payroll Tax**				26,381,920	0	(13,092,750)	(936,241)	0	14,225,411	
31	Motor Vehicle Tag Fees	Other Taxes and Fees	—		521,292	0	0	(1,052)	0	522,344	
32					521,292	0	0	(1,052)	0	522,344	

	Subtotal Other Taxes And Fees										
40	TOTAL				335,281,114	1,005,618	564,573,662	412,371,885	8,217,690	508,090,352	13,3

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged

Resubmission - inclusion of page 262-263

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	309,849			411	33,727		276,122	56	
4	7%									
5	10%	129,866,253			411	6,751,779		123,114,474	57	
6	30	197,355,247			411	2,153,048	240,212	195,442,411	32	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	327,531,349				8,938,554	240,212	318,833,007		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	327,531,349						318,833,007		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Workforce Reduction Programs	188,777	234	52,014		136,763
2	Deferred Compensation	42,511,572	131, 426.5	9,962,758	7,734,519	40,283,333
3	[a] Deferred Revenue (a)	949,181	454	354,087		595,094
4	[b] Advanced Contribution for Construction (b)	97,916,090	107,121, 451	122,036,884	158,583,395	134,462,601
5	Deferred Affiliate Taxes Payable	363,511	234	140,188		223,323
6	Long-Term Service Agreement	35,323,869	131, 242			35,323,869
7	Contract Retention	21,478,434	143, 186, 101, 107	21,478,434	8,113,800	8,113,800
8	[c] Prepaid Rent for Outdoor Lighting (c)	4,767,943	451	35,193,743	36,811,792	6,385,992
9	Renewable Generation Collateral	52,909,822	131	36,268,678	4,871,350	21,512,494
10	Vogtle 3&4 Construction	7,890,000	242, 107	17,376,801	25,000,000	15,513,199
11	Miscellaneous Deferred Credits	9,475,836	131, 421	8,906,949	33,287	602,174
12	Software Licensing	2,250,000	242	750,000		1,500,000
13	[d] Utility Services Contracts (d)	1,433,888	242	1,325,431	1,780,153	1,888,610
14	[e] Distribution Services (e)	2,030,247	451	1,453,795	1,346,616	1,923,068
47	TOTAL	279,489,170		255,299,762	244,274,912	268,464,320

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfOtherDeferredCredits
Atlanta-Jacksonville Prepaid Fiber Maintenance and Right of Way Encroachment is being amortized over 10 years and 22 years ending in 2024 and 2025, respectively. Macon Ring and Macon Spur Prepaid Fiber is being amortized over 20 years and 24 years ending in 2027 and 2026, respectively.
(b) Concept: DescriptionOfOtherDeferredCredits
Deferred credits for Contributions in Aid of Construction (CIAC) are cash advances from customers related to capital projects which are used to offset CWIP costs when incurred. Prepaid on-going maintenance over $250K for CIAC requires amortization over the life of the asset.
(c) Concept: DescriptionOfOtherDeferredCredits
Prepaid Rent for Outdoor Lighting is amortized over a 24-month period beginning in the month the payment is received.
(d) Concept: DescriptionOfOtherDeferredCredits
Deferred revenue from Utility Service Contracts is being amortized over the life of the contract which is 25 years.
(e) Concept: DescriptionOfOtherDeferredCredits
Maintenance on Atlanta Airport network underground facilities at the End Around Relocation and Concourse is being amortized over 29 years ending 2036 and 35 years ending 2043, respectively. The Dekalb County Water Plant Substation is being amortized over 33 years ending in 2043.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance End of Y (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	620,990,012	15,647,206	107,696,025			182, 254	134,449	182, 254	36,190,187	564,996,
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	620,990,012	15,647,206	107,696,025				134,449		36,190,187	564,996,
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										

17	TOTAL (Acct 281) (Total of 8, 15 and 16)	620,990,012	15,647,206	107,696,025				134,449		36,190,187	564,996,
18	Classification of TOTAL										
19	Federal Income Tax	511,162,625	9,102,729	94,826,283			182, 254	134,010	182, 254	36,190,175	461,495,
20	State Income Tax	109,827,387	6,544,477	12,869,742			182, 254	439	182, 254	12	103,501,
21	Local Income Tax										

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerate
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS			
							Debits		Credits	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amou (j)
1	Account 282									
2	Electric	4,235,571,921	(22,297,633)	(69,155,627)			182/254	26,840,492	182/254/282	98,453,
3	Gas									
4	Other (Specify)	29,082,937	(34,084,541)	(12,563,260)						
5	Total (Total of lines 2 thru 4)	4,264,654,858	(56,382,174)	(81,718,887)				26,840,492		98,453,
6	Other Income and Deductions	91,503,733			9,619,669	(10,199,990)				(971,4
7	CWIP Electric	(354,619,166)	(55,671,972)							
8	CWIP NonElectric	(824,773,801)			5,854,560	68,740,315				
9	TOTAL Account 282 (Total of Lines 5 thru 8)	3,176,765,624	(112,054,146)	(81,718,887)	15,474,229	58,540,325		26,840,492		97,482,
10	Classification of TOTAL									
11	Federal Income Tax	2,591,968,329	(99,652,361)	(54,402,682)	13,105,696	44,860,963	182/254	21,625,585	182/254	86,869,
12	State Income Tax	584,797,295	(12,401,785)	(27,316,205)	2,368,533	13,679,362	182/254	5,214,907	182/254	10,613,
13	Local Income Tax									

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 28
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				B Er
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Premium on Reacquired Debt	61,541,054	398,561	5,141,280							
4	Additional Pension Deduction	381,784,945	29,927,841	42,174							4
5	Other Basis Differences - 109	103,044,590		68,549			182/254	9,022,485	182/254	17,396,481	1
6	Other *	269,672,092	706,822,333	136,222,602			182/254		182/254	2,561,333	(a)8
9	TOTAL Electric (Total of lines 3 thru 8)	816,042,681	737,148,735	141,474,605				9,022,485		19,957,814	1,4
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	2,128,180			(368,631)	(38,645,334)					
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	818,170,861	737,148,735	141,474,605	(368,631)	(38,645,334)		9,022,485		19,957,814	1,4
20	Classification of TOTAL										

21	Federal Income Tax	643,860,741	580,641,581	106,721,042	97,991	1,730,625	182/254	7,268,075	182/254	16,342,516	1,1
22	State Income Tax	174,310,120	156,507,154	34,753,563	(466,622)	(40,375,959)	182/254	1,754,410	182/254	3,615,298	3
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

	12/31/2021	DR 410.1	CR 411.1	Debit Adj	Credit Adj	12/31/2022
Customer Advances on Const.	$ (21,588,987)	$ 18,079,702	$ (27,772,025)	$ —	$ —	$ (31,281,310)
Deferred Interest on Nuclear Fuel	9,526,776	10,425,598	(9,438,076)	—	—	10,514,298
Deferred Jobs Revenue	956,667	1,251,317	(1,168,194)	—	—	1,039,790
Emission Allowances	1,934,158	—	(4,073)	—	—	1,930,085
Unbilled Rev. - Flat Bill	8,925,584	20,376,491	(20,379,514)	—	—	8,922,561
Fuel Clause Recovery	109,317,366	438,844,931	—	—	—	548,162,297
Levelized Purchase Power	376,299	20,765,452	(19,888,572)	—	—	1,253,179
Nuclear Construction Cost Recovery	—	13,072,668	—	—	—	13,072,668
Nuclear Outage	9,145,830	6,425,788	(7,647,038)	—	—	7,924,580
Reg. Asset - Cloud Computing	8,808,970	7,248,616	(339,599)	—	—	15,717,987
Reg. Asset - COVID-19 Costs	—	6,719,908	—	—	—	6,719,908
Reg. Asset - Customer Usage Data Costs	63,484	88,694	(65,330)	—	—	86,848
Reg. Asset - IQTBEE Program	8,233	2,436	(1,866)	—	—	8,803
Reg. Asset - TOU MB Revenue Erosion	—	422,173	(83,952)	—	—	338,221
Reg. Asset - Cancelled Construction Projects	1,932,177	—	(1,937,613)	—	—	(5,436)
Reg. Asset - Obsolete Inv	—	4,136,560	(680,212)	—	—	3,456,348
Reg. Asset - Retired Units	121,302,962	154,161,837	(22,385,148)	—	—	253,079,651
Tax Legislative Adj	3,027,446	—	(1,134,768)	—	—	1,892,678
Storm Damage	18,496,460	4,800,162	(23,296,622)	—	—	—
GA Rate Change Reserve	(2,561,333)	—	—	—	2,561,333	—
	$ 269,672,092	**$ 706,822,333**	**$ (136,222,602)**	**$ —**	**$ 2,561,333**	**$ 842,833,156**

NOTE 1: DITS associated with Premium on Reacquired Debt relate to the premium on the reacquisition of certain series of first mortgage and pollution control bonds. This loss on reacquisition is recognized for tax return purposes in the year incurred, but amortized over various periods for book purposes.

NOTE 2: DITS on Additional Pension Deduction relate to actual pension costs that impact the pension fund and are currently recognized for tax return purposes. For book purposes, a deduction is taken as the pension costs are accrued.

NOTE 3: DITS on Other Basis Differences - 109 represent the tax effects of temporary differences created with FAS 109.

NOTE 4: DITS on Deferred Jobs Revenues represent revenues that have been billed for jobbing work done. The revenues are deferred on the books until all costs are accumulated. For tax purposes, the revenues are recognized currently.

NOTE 5: DITS on Emission Allowances represent actual cash payments deducted on the tax return for the purchases of emission allowances versus book accounting, which accounts for the allowances using an average weighted cost basis.

NOTE 6: DITS on Unbilled Revenues associated with Flat Bill program represent tax effect of differences between customer actual usage and contracted usage related revenues.

NOTE 7: DITS on Fuel Clause Recovery relate to recognition of the under recovery of fuel costs in revenues for book purposes currently, while these revenues are recognized for tax purposes when actually collected.
NOTE 8: DITS on Levelized Purchase Power relate to actual capacity expenses which are recognized as paid for tax purposes. For book purposes, these costs will be levelized over the term of the purchase agreement.

NOTE 9: DITS on Nuclear Outage relate to expenses incurred during scheduled outages at nuclear facilities, which are deferred on the books per a GPSC retail rate order. For book purposes, these costs will be amortized over the GPSC mandated recovery period. For tax purposes, these costs are deducted as incurred.

NOTE 10: DITS on Nuclear Construction Cost Recovery are related to the billed amounts to customers for the recovery of financing cost associated with building a nuclear plant.

NOTE 11: DITS on Other Deferred Costs - Electric are miscellaneous temporary differences.

NOTE 12: DITS on Regulatory Asset Obsolete Inventory are associated with the inventory determined to be obsolete related to the retirement of Plant Branch Units 3 and 4.

NOTE 13: Regulatory Asset Cancelled Construction Projects are associated with the cost deferrals of cancelled construction projects for retired units. These cost are expected to be amortized for books over nine years beginning in January 2014.

NOTE 14: DITS on Regulatory Assets Retired Units are associated with Net Book Value that will be amortized over the remaining useful life of the unit.

NOTE 15: DITS on Customer Advances on Construction are funds received from customers for construction work requested by customer. For tax, the funds are taxable upon receipt.

NOTE 16: DITS on Storm Damage represent actual costs deducted on the tax return as incurred, which have exceeded the book accrual allowed by the GPSC.

NOTE 17: DITS On Tax Legislative Regulatory Adjustment represent deductions made to our Other Post Retirement Benefit balance related to the Medicare Subsidy. Federal tax laws changed our anticipated tax return deduction for future years related to retiree prescription drugs as a result of the subsidy now being taxable.

NOTE 18: DITS on Other Income & Deductions represent the tax effect associated with FAS 133, Non-Utility Deferred Intercompany Gains, and miscellaneous differences. Deferred Intercompany Gains relate to the gain on the sale of transmission properties to Gulf Power Company (now Florida Power and Light Company), gain on the sale of computer equipment to Southern Company Services, and gain on sale of property to Southern Power Company.

NOTE 19: DITS on State Tax Reform Legislation are related to the expected impact of the change in the state tax rate.

NOTE 20: DITS on Regulatory Asset Customer Usage Data Costs represent costs to be recovered for acquiring customer usage data.

NOTE 21: DITS on Deferred Interest Nuclear Fuel relate to the deferral of capitalized interest on nuclear fuel for Plant Vogtle Units 3 &4.

NOTE 22: DITS on Reg. Asset – Cloud Computing are associated with the deferral of certain costs related to the implementation of new cloud based business applications used by the Company.

NOTE 23: DITS on Reg. Asset - IQTBEE (Income Qualified Tariff Based on Energy Efficiency) are related to a program for retail customers that provides energy efficiency upgrades to income qualified customers.
NOTE 24: DITS on Reg. Asset - COVID-19 costs are associated with recoverable costs from the COVID-19 pandemic.

NOTE 25: DITS on Reg. Asset - TOU MB Revenue Erosion are related to the regulatory asset created for tracking revenue erosion from Georgia Power customers using the "time of use - medium business rate."

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	[a] Deferred Income Taxes (a)	2,537,251,801	190,411	1,389,551,152	1,096,416,992	2,244,117,641
2	[b] State Tax Expense Savings (b)	1,259,608	407.4	1,259,608		
3	[c] External Decommissioning Liability (c)	750,515,289	128	203,734,940		546,780,349
4	[d] Asset Retirement Obligations (d)	353,894,605	182,411	337,519,352	427,288,665	443,663,918
5	[e] Gas and Electric Hedges (e)	79,944,615	Various	273,644,238	235,416,949	41,717,326
6	[f] DSM Over Recovery (f)	58,682,611	440,442	61,367,822	40,295,899	37,610,688
7	[g] Retiree Benefit Plans (g)	63,894,601	926	43,283,456	58,622,128	79,233,273
8	[h] Plant Retirements (h)		407.4	59,054	8,647,346	8,588,292
9	[i] Nuclear Decommissioning (i)				7,565,252	7,565,252
41	TOTAL	3,845,443,130		2,310,419,622	1,874,253,231	3,409,276,739

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The protected excess accumulated deferred income taxes associated with the remeasurement of Accumulated Deferred Income Taxes (ADITs) as a result of the Tax Cuts and Jobs Act are amortized over the related remaining property lives using the average rate assumption method in accordance with IRS normalization principles which may range up to 57 years. The unprotected excess deferred income taxes associated with the remeasurement of ADITs as a result of the Tax Cuts and Jobs Act and Georgia state income tax rate change were amortized over the three-year period ending December 31, 2022 in accordance with the Georgia PSC order in Docket No. 42516. The deferred tax assets and regulatory liabilities associated with the remaining unamortized investment tax credits are being amortized over the related remaining property lives in accordance with IRS normalization principles which may range up to approximately 45 years.

		Beginning Balance		Amortized to 411.1		Net DR/CR Adj		Ending Balance
Deferred Income Taxes	$	84,270,634	$	—	$	(10,089,133)	$	74,181,501
Protected EADIT	$	2,233,137,744	$	(47,103,082)	$	(16,098,522)	$	2,169,936,140
Unprotected EADIT	$	216,414,803	$	(161,671,579)	$	(54,743,224)	$	—
Unprotected EADIT GA State Rate Change	$	3,428,620	$	(2,561,333)	$	(867,287)	$	—

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

In accordance with the Georgia PSC order in Docket No. 36989, the Company deferred approximately $4 million of tax expense savings in 2019 as result of the reduction in state income tax rates, which was amortized over the three-year period ending December 31, 2022 as ordered by the Georgia PSC in Docket No. 42516.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The Company accrued $4 million annually through December 31, 2022, as ordered by the Georgia PSC in Docket No. 42516, to fund the external trust for future costs related to decommissioning the Company's operating nuclear plants. Effective January 1, 2023, no funding will be accrued for Plant Hatch Units 1 and 2 and Plant Vogtle Units 1 and 2 until the next base rate case as ordered by the Georgia PSC in Docket No. 44280. Annual funding accrual for Plant Vogtle Units 3 and 4 upon their in-service dates will be determined in future regulatory proceedings.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Coal Combustion Residuals (CCR) AROs are recovered through the Environmental Compliance Cost Recovery tariff, with approximately $180 million recovered in 2022 and approximately $160 million, $245 million, and $325 million expected to be recovered in 2023, 2024, and 2025, respectively, with the recovery amount for future years updated through compliance filings. Approximately $17 million annually will be recovered for non-CCR AROs through the traditional base tariffs. Other cost of removal obligations and non-CCR AROs are recovered over the related property lives, which may range up to 57 years.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Realized and unrealized gains arising from marked to market gas and electric hedges are deferred and recovered when settled as ordered by the Georgia PSC in Docket No. 16134. The Company's natural gas hedging program uses an array of derivative instruments within a 36-month time horizon, as ordered by the Georgia PSC in Docket No. 43011.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The costs associated with Demand-Side Management (DSM) initiatives are recovered through the DSM tariffs, and the revenues and expenses are trued-up based on actual results. The over or under recovery from the previous year is applied to the DSM tariffs in the year after a full calendar year through the annual compliance filings.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The credits associated with retiree benefit plans resulted from a change in valuation methodology and are being amortized over 13 years ending December 31, 2032.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

In accordance with the Georgia PSC order in Docket No. 44160, the credit balance of the remaining net book value of Plant Boulevard Unit 1 is classified as a regulatory liability. The balance was amortized at a rate equal to the unit depreciation rate approved by the Georgia PSC in Docket No. 42516 through December 31, 2022. The credit balance of the remaining net book values of Plant Boulevard Unit 1, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 as of December 31, 2022 will be amortized over a three-year period ending December 31, 2025 as ordered by the Georgia PSC in Docket No. 44280.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

In accordance with the Nuclear Regulatory Commission requirement to satisfy funding assurance for nuclear decommissioning, the Company provided funding to the external nuclear decommissioning trust. The recovery of the nuclear decommissioning trust funding will be determined by the Georgia PSC in future regulatory proceedings.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	4,513,634,027	3,688,086,167	29,085,636	27,867,774	2,347,918	2,315,911
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	4,160,629,692	3,222,104,645	32,574,680	31,344,751	325,274	321,719
5	Large (or Ind.) (See Instr. 4)	2,255,410,817	1,489,163,648	23,851,133	23,272,703	10,674	10,691
6	(444) Public Street and Highway Lighting	86,094,743	80,113,774	301,346	315,835	9,486	9,623
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways	13,696,636	9,457,165	143,691	142,978	1	1
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	11,029,465,915	8,488,925,399	85,956,486	82,944,041	2,693,353	2,657,945
11	(447) Sales for Resale	236,756,071	198,749,629	2,445,555	3,175,875		
12	TOTAL Sales of Electricity	11,266,221,986	8,687,675,028	88,402,041	86,119,916	2,693,353	2,657,945
13	(Less) (449.1) Provision for Rate Refunds	[a]237,409,901	7,790,011				
14	TOTAL Revenues Before Prov. for Refunds	11,028,812,085	8,679,885,017	88,402,041	86,119,916	2,693,353	2,657,945
15	Other Operating Revenues						
16		16,634,308	16,338,349				

	(450) Forfeited Discounts						
17	(451) Miscellaneous Service Revenues	[b]252,881,974	[d]235,311,152				
18	(453) Sales of Water and Water Power	294,255	342,622				
19	(454) Rent from Electric Property	24,681,487	23,852,963				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[c]22,801,907	[e]76,595,769				
22	(456.1) Revenues from Transmission of Electricity of Others	93,675,424	75,146,398				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	410,969,355	427,587,253				
27	TOTAL Electric Operating Revenues	11,439,781,440	9,107,472,270				

Line12, column (b) includes $ 1,506,283,827 of unbilled revenues.
Line12, column (d) includes 747,120,402 MWH relating to unbilled revenues

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ProvisionForRateRefunds

Provision for rate refund

Resubmission - Footnote added

(b) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues (Account 451)		**2022**
Outdoor Lighting	$	188,961,094
Transmission Maintenance Fees		29,668,661
Account Charges		17,959,985
Reconnect Fees		9,869,927
Returned Check Fees		5,445,036
Renewable Program Fees		853,979
Miscellaneous Small Items (each under $250,000)		123,292
Total Miscellaneous Service Revenues (Account 451)	$	252,881,974

(c) Concept: OtherElectricRevenue

Other Electric Revenues (Account 456)		**2022**
Integrated Transmission System O&M Revenue	$	23,307,518
Rate Administration Charges		6,556,581
Scheduling, System Control and Dispatching		4,593,915
Transmission Service Agreements		4,329,662
PPA Admin		4,178,435
Spare Equipment Carrying Charge		3,876,781
Revenue from Operation of Fish and Wildlife		3,648,485
Compensation for Collecting Sales Tax		3,413,534
Colocation		2,041,416
Miscellaneous Small Items (each under $250,000)		1,316,919
Joint Use Poles		734,387
Land Related Revenue		488,505
Transmission Interconnection Termination		450,000
EV Charging Stations		355,036
Realized loss on Price Protection Products		(20,867,276)
Renewable Program Fees		(15,621,991)
Total Other Electric Revenues (Account 456)	$	22,801,907

(d) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues (Account 451)		**2021**
Outdoor Lighting	$	171,057,454
Transmission Maintenance Fees		27,996,213
Account Establishment Charges		18,279,136
Reconnect Fees		9,320,613
Returned Check Fees		5,220,639
Contributions in Aid of Construction		2,678,069
Customer REC Purchase Program		378,392
Collection Fees		329,572
Miscellaneous Small Items (each under $250,000)		51,064
Total Miscellaneous Service Revenues (Account 451)	$	235,311,152

(e) Concept: OtherElectricRevenue

Other Electric Revenues (Account 456)	2021	
Transmission Service Agreements	$	29,845,690
Integrated Transmission System O&M Revenue		19,184,401
Rate Administration Charges		6,647,345
Scheduling, System Control and Dispatching		6,229,134
Spare Equipment Carrying Charge		6,152,240
Compensation for Collecting Sales Tax		2,980,045
Renewable Program Fees		2,491,866
Colocation		2,061,370
Revenue from Operation of Fish and Wildlife		1,257,136
Capacity RFP Winner Fees		1,111,370
Miscellaneous Small Items (each under $250,000)		721,360
Joint Use Poles		468,082
EV Charging Stations		324,684
Realized loss on Price Protection Products		(2,878,954)
Total Other Electric Revenues (Account 456)	$	76,595,769

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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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46	TOTAL				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	R-M Residential: Multi-Unit	13,994	1,907,791	1,902	7,358	0.1363
2	R Residential	20,634,473	2,640,142,509	1,766,456	11,681	0.1279
3	TOU-REO Time-of-Use - Residential Energy Only	82,021	10,048,369	6,330	12,957	0.1225
4	TOU-PEV Time-of-Use - Plug In Electric Vehicle	149,542	17,235,774	7,732	19,341	0.1153
5	OL_NGRE Outdoor Lighting	44,283	14,073,390	4,565	9,700	0.3178
6	OL-UN Outdoor Lighitng	17,687	1,709,703	2,095	8,443	0.0967
7	FLAR-R Flat Bill - Residential	5,779,954	787,609,708	407,955	14,168	0.1363
8	FLAT-GS Flat Bill - General Service	156	36,413	29	5,367	0.2340
9	PLS-R Power & Light - Small	34,361	4,163,539	744	46,184	0.1212
10	PLM-R Power & Light - Medium	120,048	11,388,990	172	697,953	0.0949
11	PLL-R Power & Light - Large	30,290	3,172,147	9	3,365,602	0.1047
12	Pre pay	1,112,296	149,398,192	83,538	13,315	0.1343
13	TOU-RD Time-of-Use - Residential Demand	588,031	86,283,337	62,889	9,350	0.1467
14	GS-R General Service	10,538	3,243,745	3,502	3,009	0.3078
41	TOTAL Billed Residential Sales	28,617,674	3,730,413,607	2,347,918	12,189	0.1304
42	TOTAL Unbilled Rev. (See Instr. 6)	467,962	783,220,420			1.6740
43	TOTAL	29,085,636	4,513,634,027	2,347,918	12,388	0.1552

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	SCH School Service	160,020	20,903,352	1,059	151,105	0.1306
2	SLM School Load Management	1,724,708	146,699,740	1,299	1,327,720	0.0851
3	TOU-HLF Time of Use - High Load Factor	61,062	5,113,096	16	3,816,391	0.0837
4	OLNG-BB Outdoor Lighting	13,231	1,284,441	2,473	5,350	0.0971
5	OL-NGRE Outdoor Lighting	67,219	13,565,997	4,989	13,473	0.2018
6	RTPHSLM Real Time Pricing Hour Ahead - School Load Management	39,483	2,891,369	1	39,483,380	0.0732
7	RTPDSCH Real Time Pricing Day Ahead - School Service	133,752	14,129,408	77	1,737,036	0.1056
8	RTPDSCH Real Time Pricing Day Ahead - School Load Management	524,681	47,771,047	180	2,914,893	0.0910
9	OL-UN Outdoor Lighting	309,451	30,003,764	18,396	16,822	0.0970
10	UC Unmetered Communication	100,837	18,741,929	16,542	6,096	0.1859
11	FLAT-GS Flat Bill - General Service	72,998	14,240,054	7,490	9,746	0.1951
12	RTPDHLF RTP Day Ahead - Time of Use High Load Factor	212,558	18,350,922	49	4,337,919	0.0863
13	TOU-MB Time of Use - Multiple Business	684,689	70,038,223	2,984	229,453	0.1023
14	PLS-C Power & Light - Small	3,023,040	416,290,999	62,582	48,305	0.1377
15	PLM-C Power & Light - Medium	9,553,768	1,092,628,436	32,425	294,642	0.1144
16	PLL-C Power & Light - Large	1,832,576	181,516,220	366	5,007,039	0.0991
17	TOUGSD-C Time of Use - General Service Demand	285,322	32,280,674	408	699,318	0.1131
18	OGS-C Optional General Service	3,279	845,267	172	19,064	0.2578
19	IOP-C Irrigation Off-Peak	44,949	5,230,161	691	65,049	0.1164
20	G-C Governmental	96,999	8,986,023	20	4,849,971	0.0926

21	GS-C General Service	1,233,133	251,638,043	162,893	7,570	0.2041
22	TOUEO-C Time-of-Use - Energy Only	546,327	71,791,810	6,476	84,362	0.1314
23	SASND-C Seasonal Agricultural Service - Non-Demand	926	137,935	29	31,934	0.1489
24	RTPHPLLC Real Time Pricing Hour Ahead - Power & Light Large	1,778,764	144,720,824	16	111,172,736	0.0814
25	RTPHGC RTP Hour Ahead/G-COM	191,208	16,499,291	3	63,736,114	0.0863
26	RTPGOVC Real Time Pricing Day Ahead - Governmental	128,098	11,232,454	7	18,299,713	0.0877
27	RTGSDC Real Time Pricing Day Ahead - Time of Use - General Service Demand	137,893	13,996,786	39	3,535,715	0.1015
28	RTPDPLLC Real Time Pricing Day Ahead - Power & Light Large	2,438,820	224,616,034	244	9,995,162	0.0921
29	RTPDPLMC Real Time Pricing Day Ahead - Power & Light Medium	2,546,133	236,394,550	929	2,740,724	0.0928
30	FPA- COM Fixed Pricing Alternative	783,882	59,811,010	167	4,693,904	0.0763
31	SAS-COM Seasonal Agricultural Service	20,150	1,899,094	201	100,251	0.0942
32	APS-COM Agricultural Process Service	9,440	883,856	42	224,760	0.0936
33	FSTOU-C Farm Service	68,038	7,584,836	1,780	38,223	0.1115
34	RTPDTEOC Real Time Pricing Day Ahead - Time of Use	5,267	529,433	5	1,053,489	0.1005
35	TOUSCFC Time of Use - Supplier Choice FPO	84,496	3,187,664	36	2,347,101	0.0377
36	RTDFPAC RTP Day Ahead - Fixed Pricing Alternative	51,041	4,170,096	11	4,640,111	0.0817
37	TOUSC-C Time of Use Supplier Choice	40,648	3,042,590	40	1,016,195	0.0749
38	TOURN-C Time of Use Revenue Neutral	306,179	24,783,501	54	5,669,988	0.0809
39	RTDRN-C RTP Day Ahead - Revenue Neutral	1,099,178	91,571,570	69	15,930,109	0.0833
40	RTHRN-C RTP Hour Ahead - Revenue Neutral	1,915,854	152,362,431	10	191,585,374	0.0795
41	RTDPLSC RTP Day Ahead - Power & Light Supplier Choice	15,597	1,474,823	4	3,899,267	0.0946
41	TOTAL Billed Small or Commercial	32,345,694	3,463,839,753	325,274	99,440	0.1071
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	228,986	696,789,939			3.0430
43	TOTAL Small or Commercial	32,574,680	4,160,629,692	325,274	100,144	0.1277

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SALES OF ELECTRICITY BY RATE SCHEDULES

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	OL-NGRE Outdoor Lighting	2,533	509,234	137	18,489	0.2010
2	OL-UN Outdoor Lighting	15,308	1,463,091	419	36,534	0.0956
3	FLAT-GS Flat Bill - General Service	232	50,347	33	7,024	0.2172
4	PLS-I Power & Light - Small	62,569	8,320,779	1,226	51,035	0.1330
5	PLM-I Power & Light - Medium	1,017,260	114,822,250	2,336	435,471	0.1129
6	PLL-I Power & Light - Large	613,738	60,532,625	121	5,072,215	0.0986
7	TOUGSD-I Time of Use - General Service Demand	197,008	22,298,877	168	1,172,669	0.1132
8	OGS-I Optional General Service	5,848	1,276,798	75	77,971	0.2183
9	IOP-I Irrigation Off-Peak	2,787	219,092	16	174,206	0.0786
10	GS- I General Service	27,648	5,986,790	4,414	6,259	0.2165
11	TOUEO-I Time-of-Use - Energy Only	43,749	5,602,834	513	85,281	0.1281
12	SASND-I Seasonal Agricultural Service - Non-Demand	398	60,757	17	23,413	0.1526
13	RTPHPLLI Real Time Pricing Hour Ahead - Power & Light Large	4,666,920	368,705,064	58	80,464,141	0.0790
14	RTHPLMI Real Time Pricing Hour Ahead - Power & Light Medium	686,639	57,532,698	10	68,663,905	0.0838
15	RTPDGSDI Real Time Pricing Day Ahead - Time of Use - General Service Demand	213,336	21,522,299	40	5,333,394	0.1009
16	RTPHGSDI Real Time Pricing Hour Ahead - Time of Use - General Service Demand	42,719	3,892,240	2	21,359,314	0.0911
17	RTPDPLLI Real Time Pricing Day Ahead - Power & Light Large	2,715,592	241,309,613	193	14,070,422	0.0889
18	RTDPLMI Real Time Pricing Day Ahead - Power & Light Medium	1,504,143	137,181,391	291	5,168,878	0.0912
19		1,422,468	94,074,086	126	11,289,428	0.0661

	FPA-IND Fixed Pricing Alternative					
20	SASIND Seasonal Agricultural Service	7,569	629,036	57	132,792	0.0831
21	APS-IND Agricultural Process Service	62,985	4,886,804	97	649,332	0.0776
22	FSTOU-I Farm Service Time of Use	255	28,618	7	36,492	0.1120
23	RTHTEOI Real Time Pricing Hour Ahead - Time Of Use - Energy Only	61,109	5,542,466	1	61,109,138	0.0907
24	RTDTEOI Real Time Pricing Day Ahead - Time Of Use - Energy Only	2,682	260,739	4	670,447	0.0972
25	RTPDAPSI Real Time Pricing Day Ahead - Agricultural Process Service	29,023	2,459,738	5	5,804,569	0.0848
26	TOUSCFI Time of Use Supplier Choice FPO	295,299	9,970,141	11	26,845,379	0.0338
27	RTDFPAI RTP Day Ahead - Fixed Pricing Alternative	175,165	13,009,690	17	10,303,820	0.0743
28	TOUSCI Time of Use Supplier Choice	188,500	12,068,642	6	31,416,722	0.0640
29	RTHFPAI RTP Hour Ahead - Fixed Pricing Alternative	300,928	19,516,186	3	100,309,329	0.0649
30	TOURN-I Time of Use Revenue Neutral	740,727	55,347,577	76	9,746,413	0.0747
31	RTDRN-I RTP Day Ahead - Revenue Neutral	1,917,858	160,161,738	107	17,923,904	0.0835
32	RTHRN-I RTP Hour Ahead - Revenue Neutral	6,112,810	467,830,709	56	109,157,291	0.0765
33	RTDPLSI RTP Day Ahead/PLS-IND	152,173	9,703,449	4	38,043,213	0.0638
34	RTHPLSI RTP Hour Ahead/PLS-IND	195,212	15,343,594	1	195,212,385	0.0786
35	TOUMBI Time of Use --Multiple business	2,254	221,280	26	86,708	0.0982
36	EAF-IND Electric Arc Furnace	315,517	16,874,117	1	315,517,162	0.0535
41	TOTAL Billed Large (or Ind.) Sales	23,800,961	1,939,215,389	10,674	2,229,181	0.0815
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	50,172	316,195,428			6.3020
43	TOTAL Large (or Ind.)	23,851,133	2,255,410,817	10,674	2,233,880	0.0946

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RLG Roadway Lighting Governmental	122,566	52,643,010	982	124,813	0.4295
2	OL-Govt Outdoor Lighting - Governmental	137,850	23,466,853	3,422	40,284	0.1702
3	TC Traffic Control	37,974	1,960,718	4,548	8,350	0.0516
4	OL-UN Outdoor Lighting	164	15,800	14	11,686	0.0966
5	TC-M Traffic Control Metered	2,792	293,025	520	5,369	0.1050
41	TOTAL Billed Public Street and Highway Lighting	301,346	78,379,406	9,486	31,767	0.2601
42	TOTAL Unbilled Rev. (See Instr. 6)		7,715,337			0.0000
43	TOTAL	301,346	86,094,743	9,486	31,767	0.2857

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Marta Electric Transportation	143,691	11,463,151	1	143,691,166	0.0798
41	TOTAL Billed Sales To Railroads and Railways	143,691	11,463,151	1	143,691,166	0.0798
42	TOTAL Unbilled Rev. (See Instr. 6)		2,233,485			0.0000
43	TOTAL	143,691	13,696,636	1	143,691,166	0.0953

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		(a)237,409,901			

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FOOTNOTE DATA

(a) Concept: ProvisionForRateRefunds
Provision for rate refund Resubmission - Footnote added

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	85,209,366	9,223,311,306	2,693,353	146,063,743	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	747,120	[a]1,806,154,609			
43	TOTAL - All Accounts	85,956,486	11,029,465,915	2,693,353	146,063,743	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesUnbilled

The Total Unbilled Rev included in total sales of electricity on pg 300 line 12 is $1,806,154,609. The Total Unbilled Rev on pg 304 line 47 includes $75,693,308 of Unbilled Revenue. The difference of $1,730,461,301 is adjustments including:

FCR	$	1,646,056,735
NCCR		64,590,348
DSM		21,071,922
Flatbill Revenue Recognition		(11,340)
Miscellaneous		(1,246,364)
Total Difference	$	1,730,461,301

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges dur the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settler for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership intere affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes prc load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get ou the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide ar explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly bi demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demar column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integ demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its m peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to th purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non- amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Tota (h+ (
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	Associated Energy Cooperative Inc.	OS	T4				18		942		
2	City of Dalton, Dalton Utilities	LU	T4				10,111	389,861	534,845		9

3	City of Tallahassee, Florida	OS	T4				474		32,671		
4	City of Troy, Alabama	OS	T5						275,850		2
5	Constellation Energy	OS	T5						561,344		5
6	Dominion Energy	OS	T4				9,995		4,671,877		4,6
7	Duke Energy Carolinas, LLC	OS	T4				4,740		232,322		2
8	Duke Energy Florida	OS	T4				8,841		632,357		6
9	Eagle Energy Partners I, L.P.	OS	T4				16,661		1,051,590		1,0
10	Endure Energy, LLC	OS	T4				183		8,104		
11	Energy United Electric Membership Corporation	LU	T4				243,957	25,040,140	11,697,496		36,7
12	Exelon Generation Company, LLC	OS	T4				59,876		3,807,059		3,8
13	Flint EMC	LU	T4				201,576	16,615,524	9,210,824		25,8
14	Florida Power & Light Company	OS	T4				4,215		339,005		3
15	KGen Sandersville LLC	OS	T5						36,121		
16	Louisville Gas & Electric	OS	0						723		
17	Macquarie Energy, LLC	OS	T4				23,482		1,493,783		1,4
18	Mercuria Energy America, Inc	OS	T4				16,126		1,153,008		1,1
19	Midwest Independent Trans System	OS	T4				18,316		372,759		3
20	Morgan Stanley Capital Group, Inc.	OS	T4				7,595		512,808		5
21	Municipal Electric Authority Of Georgia	OS	T4				992,269	196,000	83,453,962		83,6
22	NextEra Gulf	OS	RS-138				15,913		698,537		6
23	North Carolina EMC	OS	T4				53		3,336		
24	NTE Carolinas	OS	T4				190		10,589		
25	Oglethorpe Power Corporation	OS	T4				6,163		463,812		4

26	Orlando Utilities Commission	OS	T4				1,311		70,533		
27	PJM Interconnection	OS	T4				9,558		588,782		5
28	PowerSouth Energy Cooperative	OS	T4					29,340			
29	Rainbow Energy Marketing Corporation	OS	T4				1,995		135,496		1
30	Santa Rosa	OS	T5						95,533		
31	Seminole Electric Cooperative	OS	T4				336,441	3,521,441	25,528,111		29,0
32	South Carolina Electric & Gas Company	OS	T4						523		
33	South Carolina Public Service Authority	OS	T4				672	1,150,505	66,429		1,2
34	South Mississippi Electric Power Association	OS	T4						85,658		
35	Southern Company Services	OS	RS-138				307,683	1,992,000	29,547,914		31,5
36	Southwest Power Pool, Inc	OS	T4						262		
37	Tampa Electric Company	OS	T4				896		76,636		
38	Tennessee Valley Authority	OS	T4				7,251		2,396,777		2,3
39	The Energy Authority	OS	T4				135,581		7,754,590		7,7
40	Tri-County EMC	LU	T4				1,861		107,951		1
41	Washington County Power, LLC (Mackinaw Power)	OS	T5						1,223		
42	Westar Energy, Inc.	OS	T4				1,552		109,118		1
15	Subtotal - RQ										
16	Subtotal-Non-RQ						2,445,555	48,934,811	187,821,260		236,7
17	Total						2,445,555	48,934,811	187,821,260		236,7

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	17,327,557	17,910,694
5	(501) Fuel	641,245,781	403,707,925
6	(502) Steam Expenses	15,955,166	33,800,305
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	15,904,526	2,574,206
10	(506) Miscellaneous Steam Power Expenses	39,152,777	49,875,354
11	(507) Rents		
12	(509) Allowances	15,818	18,039
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	729,601,625	507,886,523
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	13,439,495	15,916,169
16	(511) Maintenance of Structures	19,257,216	15,658,822
17	(512) Maintenance of Boiler Plant	72,778,180	87,351,214
18	(513) Maintenance of Electric Plant	10,907,208	13,204,778
19	(514) Maintenance of Miscellaneous Steam Plant	5,629,049	5,536,978
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	122,011,148	137,667,961
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	851,612,773	645,554,484
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	87,308,913	80,227,763
25	(518) Fuel	122,119,830	127,968,274
26	(519) Coolants and Water	8,897,254	4,387,961
27	(520) Steam Expenses	12,290,634	22,376,126
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		

30	(523) Electric Expenses	203,492	
31	(524) Miscellaneous Nuclear Power Expenses	122,726,712	110,367,537
32	(525) Rents	657,392	368,559
33	TOTAL Operation (Enter Total of lines 24 thru 32)	354,204,227	345,696,220
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	21,649,067	11,618,738
36	(529) Maintenance of Structures	5,021,341	10,206,233
37	(530) Maintenance of Reactor Plant Equipment	13,650,464	30,496,765
38	(531) Maintenance of Electric Plant	13,404,054	14,800,077
39	(532) Maintenance of Miscellaneous Nuclear Plant	15,906,614	10,790,800
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	69,631,540	77,912,613
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	423,835,767	423,608,833
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	10,838,773	2,946,104
45	(536) Water for Power	1,853,297	2,068,723
46	(537) Hydraulic Expenses	2,185,328	3,010,409
47	(538) Electric Expenses	5,002,759	5,819,329
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,769,099	7,972,633
49	(540) Rents	51,125	49,915
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	25,700,381	21,867,113
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	200,836	2,278,976
54	(542) Maintenance of Structures	9,963,336	2,746,503
55	(543) Maintenance of Reservoirs, Dams, and Waterways	4,740,088	2,632,024
56	(544) Maintenance of Electric Plant	5,047,619	6,164,337
57	(545) Maintenance of Miscellaneous Hydraulic Plant	906,290	455,175
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	20,858,169	14,277,015
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	46,558,550	36,144,128
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	8,541,479	10,665,476
63	(547) Fuel	1,722,485,510	917,551,381
64	(548) Generation Expenses	10,240,179	6,845,018
64.1	(548.1) Operation of Energy Storage Equipment		

65	(549) Miscellaneous Other Power Generation Expenses	31,060,799	28,693,528
66	(550) Rents	5,587	58,219
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	1,772,333,554	963,813,622
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	7,946,019	6,366,653
70	(552) Maintenance of Structures	10,851,373	10,043,681
71	(553) Maintenance of Generating and Electric Plant	39,633,875	38,530,610
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,438,197	4,545,539
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	60,869,464	59,486,483
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	1,833,203,018	1,023,300,105
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	2,284,753,973	1,514,640,167
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	3,859,399	13,258,780
78	(557) Other Expenses	21,068,781	16,096,446
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	2,309,682,153	1,543,995,393
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	5,464,892,261	3,672,602,943
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,529,389	6,682,571
85	(561.1) Load Dispatch-Reliability	6,872,688	9,209,101
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	9,081,285	9,569,638
87	(561.3) Load Dispatch-Transmission Service and Scheduling	249,933	414,335
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	3,914,361	
90	(561.6) Transmission Service Studies	150,603	564,956
91	(561.7) Generation Interconnection Studies	433,615	168,476
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	6,516,413	3,172,914
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	2,198,442	1,136,757
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	5,314,696	2,085,530

97	(566) Miscellaneous Transmission Expenses	18,780,513	19,029,543
98	(567) Rents	(38,980,260)	(26,945,984)
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	22,061,678	25,087,837
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	17,356,883	14,709,682
102	(569) Maintenance of Structures	203,738	909,637
103	(569.1) Maintenance of Computer Hardware	3,023,881	447,860
104	(569.2) Maintenance of Computer Software	878,395	2,085,931
105	(569.3) Maintenance of Communication Equipment	6,100	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	21,591,223	21,388,056
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	49,032,891	61,804,953
109	(572) Maintenance of Underground Lines	322,269	1,261,896
110	(573) Maintenance of Miscellaneous Transmission Plant	1,713,819	4,485
111	TOTAL Maintenance (Total of Lines 101 thru 110)	94,129,199	102,612,500
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	116,190,877	127,700,337
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131			

	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	24,567,564	18,640,493
135	(581) Load Dispatching	8,315,033	18,062,590
136	(582) Station Expenses	1,365,610	2,065,099
137	(583) Overhead Line Expenses	2,506,397	3,873,630
138	(584) Underground Line Expenses	20,760,781	16,006,178
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	515	4,795
140	(586) Meter Expenses	31,085,224	26,405,422
141	(587) Customer Installations Expenses	2,977,012	1,901,342
142	(588) Miscellaneous Expenses	49,844,869	32,460,092
143	(589) Rents	3,314,278	3,265,994
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	144,737,283	122,685,635
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	15,063,647	19,783,566
147	(591) Maintenance of Structures	1,102,000	2,204,106
148	(592) Maintenance of Station Equipment	21,291,250	14,270,179
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	201,172,289	143,156,333
150	(594) Maintenance of Underground Lines	28,860,934	24,356,856
151	(595) Maintenance of Line Transformers	6,252,535	4,399,769
152	(596) Maintenance of Street Lighting and Signal Systems	20,824,927	14,142,403
153	(597) Maintenance of Meters	4,732,521	2,933,297
154	(598) Maintenance of Miscellaneous Distribution Plant		(288,134)
155	TOTAL Maintenance (Total of Lines 146 thru 154)	299,300,103	224,958,375
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	444,037,386	347,644,010
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	3,798,599	10,708,933
160	(902) Meter Reading Expenses	26,001,347	26,146,068
161	(903) Customer Records and Collection Expenses	85,132,243	102,493,447
162	(904) Uncollectible Accounts	20,733,836	15,434,755
163	(905) Miscellaneous Customer Accounts Expenses	9,512,952	330,486
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	145,178,977	155,113,689

165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	83	
168	(908) Customer Assistance Expenses	71,709,490	70,580,049
169	(909) Informational and Instructional Expenses	(7,781)	734,187
170	(910) Miscellaneous Customer Service and Informational Expenses	1,152,801	2,945,101
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	72,854,593	74,259,337
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	611,014	
175	(912) Demonstrating and Selling Expenses	34,100,375	39,809,531
176	(913) Advertising Expenses	512,783	
177	(916) Miscellaneous Sales Expenses	6,039,711	566,809
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	41,263,883	40,376,340
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	84,775,799	60,359,643
182	(921) Office Supplies and Expenses	2,906,196	16,746,587
183	(Less) (922) Administrative Expenses Transferred-Credit	2,032,136	6,411,032
184	(923) Outside Services Employed	145,036,496	82,707,395
185	(924) Property Insurance	229,558,038	233,202,588
186	(925) Injuries and Damages	30,645,116	33,469,544
187	(926) Employee Pensions and Benefits	(54,634,235)	(7,158,730)
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	17,939,177	7,107,308
190	(929) (Less) Duplicate Charges-Cr.	15,524,372	9,124,716
191	(930.1) General Advertising Expenses	17,504,903	17,345,561
192	(930.2) Miscellaneous General Expenses	18,104,593	10,421,193
193	(931) Rents	7,498,843	6,405,592
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	481,778,418	445,070,933
195	Maintenance		
196	(935) Maintenance of General Plant	36,135,657	23,249,876
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	517,914,075	468,320,809
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	6,802,332,052	4,886,017,465

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits fo imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explai respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes prc planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consume

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside f and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settle

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the co tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly avera non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60 reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the b
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, r receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Pur (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 4
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		C
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
1	Albany Renewable Energy, LLC	LU					380,643				
2	ASI DG Group A Solar Contracts	(9) OS					69,598				
3	Associated Energy Cooperative Inc.	OS					4,961				
4	Augusta Canal Authority	LU					11,924				

5	BFI Waste Systems	LU					0				
6	Birdsong Corporation	LU					843				
7	Bulldog Solar, LLC	LU					0				
8	CAC Contract	LU					667				
9	Calpine Energy Services	OS					0				
10	Carters	LU					0				
11	Chatsworth Water Works	LU					916				
12	City of Jesup	LU					169				
13	City of Tallahassee, Florida	OS					1,252				
14	City of Troy, Alabama	OS					0				
15	Clayton County	LU					0				
16	Coca Cola	LU					40,983				
17	Constellation Energy	OS					0				
18	Conyers Renewable Power LLC	LU					15,932				
19	Dominion Energy	OS					4,507				
20	Dublin Solar I LLC	LU					6,849				
21	Duke Energy Carolinas, LLC	OS					607				
22	Duke Energy Florida LLC	OS					3,958				
23	Eagle Energy Partners I, L.P.	OS					20,117				
24	Effingham County Power, LLC - PPA	OS					0				
25	Endure Energy, LLC	OS					0				
26	Enterprise Mill, LLC	LU					1,056				
27	Exelon Generation Company, LLC	OS					33,043				
28	International Paper - Flint River	LU					176,786				
29	Florida Power & Light Company	OS					10,424				
30		LU					395,590				

	GRP, LLC - Franklin										
31	Goatrock - IIC	OS					0				
32	Graphic Packaging International	LU					14,366				
33	[a] Green Energy	OS					490,534				
34	Green Power Solutions Inc	LU					190,987				
35	Hartwell	LU					0				
36	Hecate Energy Old Midville Rd, LLC	LU					35,120				
37	Hercules	LU					0				
38	Hickory Park Solar LLC (Broken Spoke)	LU					424,951				
39	Hillabee	LU					0				
40	HSH Pembroke LLC	LU					1,721				
41	IKEA Atlanta	LU					79				
42	IKEA Savannah	LU					788				
43	International Paper	LU					10				
44	International Paper - Savannah	LU					2,254				
45	Invenergy	LU					368,927				
46	Jacksonville Electric Authority	OS					0				
47	KGen Sandersville LLC	OS					0				
48	Louisville Gas & Electric	OS					2,715				
49	Mackinaw Power LLC	LU					1,108,386				2
50	Macquarie Energy, LLC	OS					727,974				
51	GRP, LLC - Madison	LU					374,734				
52	MARTA	LU					94				
53	MAS Georgia LFG LLC	LU					122,037				
54	MCLB Albany (NAVFEC)	LU					7,626				
55	MEAG PSSA	LU					668,878				
56	Mercuria Energy America, Inc	LU					7,698				

57	Mid Georgia Cogen LP	LU					461,807				
58	Midwest Independent Trans System	OS					244,951				
59	Morgan Stanley Capital Group, Inc.	OS					97,731				
60	MPC Generating, LLC	OS					0				
61	Municipal Electric Authority Of Georgia	LU					221,498				
62	NANTR-OATT-FERC-AttK-Ntwk-Oth	OS					0				
63	NextEra Gulf	OS					1,386,488				
64	NextEra Solar	LU					1,956,178				
65	North Carolina EMC	OS					500				
66	North Carolina Municipal Power Agency #1	OS					203				
67	NTE Carolinas	SF					57				
68	Oglethorpe Power Corporation	LU					26,256				
69	Origis Energy	LU					588,674				
70	Orlando Utilities Commission	OS					377				
71	Packaging Corporation of America	LU					3,827				
72	Piedmont Green Power	LU					398,057				
73	PJM Interconnection	OS					6,979				
74	International Paper - Port Wentworth	LU					204,499				
75	PowerSouth Electric Membership Co.	OS					0				
76	Rainbow Energy Marketing Corporation	OS					58,269				
77	Rayonier Inc	LU					83				
78	Richland Solar Center LLC	LU					41,864				
79	Rincon Solar I, LLC	LU					31,058				
80	Russell	OS					0				

81	Santa Rosa	OS					0				
82	[b] Southern Electric Generating Co	OS					649,827				
83	Simon Solar Farm	LU					52,357				
84	Solar Design & Development LLC	OS					1,261				
85	Solar Glynn, LLC	LU					31,704				
86	Sonny Solar, LLC	LU					2,158				
87	South Carolina Public Service Authority	OS					2,439				
88	South Mississippi Electric Power Association	OS					0				
89	[c] Southern Company Services	OS					16,025,660		16,387,588	16,188,234	
90	[d] Southern Power Company	OS					3,787,648		0	0	9
91	Southwest Power Pool, Inc	OS					0				
92	SOWEGA Dahlberg	OS					0				
93	Star Thread - Barnett Shoals Inc	LU					6,890				
94	Sustaining Power Solutions LLC	LU					715,143				
95	Tampa Electric Company	OS					5,675				
96	Tenaska Heard County Georgia	LU					751,219				4
97	Tennessee Valley Authority	OS					93,843				
98	The Energy Authority	OS					6,825				
99	Thurmond	OS					0				
100	Transalta Energy Marketing (US) Inc.	OS					0				
101	Verizon Communications	OS					102				
102	Wansley	OS					0				
103		OS					0				

	Washington County Power, LLC (Mackinaw Power)										
104	West Georgia Generating Co, LLC	OS					0				
105	Westar Energy, Inc.	OS					0				
106	WM Renewable Energy, LLC	LU					44,823				
15	TOTAL						33,637,632	0	16,387,588	16,188,234	23

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Renewable programs are related to Renewable Energy Development Initiative Utility Scale Requests for Proposal and Simple Solar programs implementation and administrative costs.
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Southern Electric Generating Company is 50% owned by each of Georgia Power and Alabama Power. Prior year amounts were included in totals reported for Southern Company Services.
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Southern Company Services is a subsidiary of Southern Company.
(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Southern Power Company is a subsidiary of Southern Company.
(e) Concept: StatisticalClassificationCode
OS-Unless indicated by FERC Rate Schedule Number, these are market-based purchases of non-firm energy from power marketing companies that have applications on file with the FERC.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions refe

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-tr
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acro respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Netw - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Tra Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior re General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under whic
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the subs specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in colum basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related t from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If nc footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on l
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSF Megawat Hours Receive (i)
1	Southeastern Power Administration	Southeastern Power Administration	Southeastern Power Administration Preference Customers	FNO	(g) 415	N/A	N/A	379	(z)623,0
2	Tennessee Valley Authority	Tennessee Valley Authority	Distributors of Tennessee Valley Authority	FNO	(t) 160	N/A	N/A	(w)128	735,4
3	PowerSouth Energy Cooperative	PowerSouth Energy Cooperative	PowerSouth Energy Cooperative	FNO	225	N/A	N/A	712	4,001,7
4	Alabama Municipal Electric Authority	Alabama Municipal Electric Authority	Alabama Municipal Electric Authority	FNO	474	N/A	N/A	470	3,306,0
5	Cooperative Energy	South Mississippi Electric Power Association	South Mississippi Electric Power Association	FNO	496	N/A	N/A	641	3,458,1
6	City of Troy	City of Troy	City of Troy	FNO	504	N/A	N/A	61	469,5
7	City of Evergreen	City of Evergreen	City of Evergreen	FNO	542	N/A	N/A	10	57,0
8	City of Hartford	City of Hartford	City of Hartford	FNO	543	N/A	N/A	3	28,0
9				FNO	544	N/A	N/A	13	88,3

	City of Robertsdale	City of Robertsdale	City of Robertsdale						
10	FPL2004 - Lakewood & Clear Springs	Florida Power & Light	Florida Power & Light	FNO	699	N/A	N/A		3
11	FPL2014 - Exxon & Blackjack	Florida Power & Light	Florida Power & Light	FNO	717	N/A	N/A	11	50,4
12	EXELON GENERATION COMPANY, LLC	EXELON GENERATION COMPANY, LLC	Georgia Transmission Corporation	[g] LFP	TSA	Hillabee	Georgia Transmission Corporation	210	[aa] 1,247,7
13	FLORIDA POWER & LIGHT COMPANY	FLORIDA POWER & LIGHT COMPANY	Florida Power & Light	[e] LFP	TSA	SOCO	FPLNW	65	
14	FLORIDA POWER & LIGHT COMPANY	FLORIDA POWER & LIGHT COMPANY	Florida Power & Light	[f] LFP	TSA	SOCO	FPLNW	124	485,7
15	FLORIDA POWER & LIGHT COMPANY	FLORIDA POWER & LIGHT COMPANY	Florida Power & Light	[g] LFP	TSA	SOCO	FPLNW	215	423,1
16	FLORIDA POWER & LIGHT COMPANY	FLORIDA POWER & LIGHT COMPANY	Florida Power & Light	[h] LFP	TSA	SOCO	FPLNW	489	90,4
17	JACKSONVILLE ELECTRIC AUTHORITY	JACKSONVILLE ELECTRIC AUTHORITY	Jacksonville Electric Authority	[i] LFP	TSA	Vogtle	Jacksonville Electric Authority	42	241,2
18	JACKSONVILLE ELECTRIC AUTHORITY	JACKSONVILLE ELECTRIC AUTHORITY	Jacksonville Electric Authority	[j] LFP	TSA	Vogtle	Jacksonville Electric Authority	61	419,8
19	JACKSONVILLE ELECTRIC AUTHORITY	JACKSONVILLE ELECTRIC AUTHORITY	Jacksonville Electric Authority	[k] LFP	TSA	Vogtle	Jacksonville Electric Authority	103	684,3
20	MACQUARIE	MACQUARIE	Macquarie Energy LLC	[l] LFP	TSA	SOCO	FPL	200	505,8
21	MERCURIA ENERGY AMERICA, LLC.	MERCURIA ENERGY AMERICA, LLC.	Georgia Transmission Corporation	[m] LFP	TSA	Lindsay Hill	Georgia Transmission Corporation	220	859,1
22	North Carolina Electric Membership Corporation	North Carolina Electric Membership Corporation	Duke Power Company	[n] LFP	TSA	SOCO	Duke Energy	44	40,6
23	POWERSOUTH ENERGY COOPERATIVE	POWERSOUTH ENERGY COOPERATIVE	PowerSouth Energy Cooperative	[o] LFP	TSA	SOCO	FPLNW	139	273,4
24	SEMINOLE ELECTRIC COOPERATIVE INCORPORATED	SEMINOLE ELECTRIC COOPERATIVE INCORPORATED	Florida Power & Light	[p] LFP	TSA	SOCO	Florida Power & Light	50	160,1
25	SEMINOLE ELECTRIC COOPERATIVE INCORPORATED	SEMINOLE ELECTRIC COOPERATIVE INCORPORATED	Florida Power & Light	[q] LFP	TSA	SOCO	Florida Power & Light	100	395,1
26	MERCURIA ENERGY AMERICA, LLC.	MERCURIA ENERGY AMERICA, LLC.	Georgia Transmission Corporation	[r] LFP	TSA	SOCO	Georgia Transmission Corporation	300	625,6
27	[a] VARIOUS Non Firm Customers	[c] VARIOUS Non Firm Customers	VARIOUS	NF	TSA	[u] VARIOUS	[v] VARIOUS	[x] 0	[ab] 530,2
28			VARIOUS	SFP	TSA	VARIOUS	VARIOUS	[y] 0	[ac] 13,746,6

	(b) VARIOUS Short Term Firm Customers	VARIOUS Short Term Firm Customers							
29	VARIOUS Tariff Customers	VARIOUS Tariff Customers	VARIOUS	OS	TSA	VARIOUS	VARIOUS		
35	TOTAL							4,790	33,547,6

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Various Non-Firm Point-to-Point Transmission Service customers under the Tariff.

(b) Concept: PaymentByCompanyOrPublicAuthority

Various Short-Term Firm Point-to-Point Transmission Service customers under the Tariff

(c) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Various entities pursuant to the terms and conditions of the Tariff

(d) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(e) Concept: StatisticalClassificationCode

Termination Date: January 1, 2036

(f) Concept: StatisticalClassificationCode

Termination Date: January 1, 2036

(g) Concept: StatisticalClassificationCode

Termination Date: January 1, 2024

(h) Concept: StatisticalClassificationCode

Termination Date: January 1, 2024

(i) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(j) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(k) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(l) Concept: StatisticalClassificationCode

Termination Date: June 1, 2023

(m) Concept: StatisticalClassificationCode

Termination Date: May 1, 2027

(n) Concept: StatisticalClassificationCode

Termination Date: January 1, 2027

(o) Concept: StatisticalClassificationCode

Termination Date: January 1, 2029

(p) Concept: StatisticalClassificationCode

Termination Date: June 1, 2024

(q) Concept: StatisticalClassificationCode

Termination Date: January 1, 2029

(r) Concept: StatisticalClassificationCode

Termination Date: June 1, 2022

(s) Concept: RateScheduleTariffNumber

FERC Rate Schedule 415, Agreement for Network Integration Transmission Service and Complementary Services. FERC Electric Tariff Fourth Revised Volume No. 5, the Southern Company electric operating companies (Alabama Power Company, Georgia Power Company, and Mississippi Power Company) Open Access Transmission Tariff (the "Tariff"). The Southern Company electric operating companies collectively are the Transmission Provider under the Tariff and operate their transmission facilities as a single integrated system.

(t) Concept: RateScheduleTariffNumber

Line Nos. 2 through 22 Column: e

FERC Electric Tariff Fourth Revised Volume No. 5, the Tariff.

(u) Concept: TransmissionPointOfReceipt

Various points of receipt.

(v) Concept: TransmissionPointOfDelivery
Various points of delivery.
(w) Concept: BillingDemand
The billing demand is based on a rolling 12-month average of the Transmission Customer's load under the Tariff coincident with the Transmission Provider's monthly transmission peak load. The demand reported in column h is the most recent 12-month average load for the quarter.
(x) Concept: BillingDemand
Various - Total billing demand varies based on the duration of service (e.g. hourly, daily, weekly, or monthly).
(y) Concept: BillingDemand
Various - Total billing demand varies based on the duration of service (e.g. daily, weekly, or monthly).
(z) Concept: TransmissionOfElectricityForOthersEnergyReceived
Total MWH received by the Southern Company electric operating companies for Network Integration Transmission Service.
(aa) Concept: TransmissionOfElectricityForOthersEnergyReceived
Total MWH received by Southern Company electric operating companies for Long-Term Firm Point-to-Point Transmission Service.
(ab) Concept: TransmissionOfElectricityForOthersEnergyReceived
Total MWH received by Southern Company electric operating companies for Non-Firm Point-to-Point Transmission Service.
(ac) Concept: TransmissionOfElectricityForOthersEnergyReceived
Total MWH received by Southern Company electric operating companies for Short-Term Firm Point-to-Point Transmission Service.
(ad) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Total MWH delivered by the Southern Company electric operating companies for Network Integration Transmission Service.
(ae) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Total MWH delivered by Southern Company electric operating companies for Long-Term Firm Point-to-Point Transmission Service.
(af) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Total MWH delivered by the Southern Company electric operating companies for Non-Firm Point-to-Point Transmission Service.
(ag) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Total MWH delivered by Southern Company electric operating companies for Short-Term Firm Point-to-Point Transmission Service.
(ah) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Amount of charges allocated to the respondent.
(ai) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
The Southern Company electric operating companies' Charge for Recovery of the FERC Annual and Attachment K Charges.
(aj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Various Long-Term Firm, Conditional Long-Term Firm, and Network Integration Transmission Service Customers that purchased service during January 2021 through December 2021 and will receive Tariff True-Up refunds.

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TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy	OS	18,173				74,749	74,749
2	Midwest Independent Trans System	OS	270,844				3,053,738	3,053,738
3	Southern Power (EMC 11)	OS	706,657				321,686	321,686
4	Southern Company Services (Self-Use)	OS	278,156				1,301,598	1,301,598
5	Tennessee Valley Authority	OS	19,344				544,273	544,273
6	Florida Power & Light Company	OS	3,424				18,596	18,596
7	Pennsylvania Jersey Maryland	OS	140				56	56
	TOTAL		1,296,738				5,314,696	5,314,696

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	979,332
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,914,783
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	54,608
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Directors' Fees and Expenses	2,383,440
7	Substance Abuse Testing	120,873
8	Community Development	2,654,044
9	Agent Fees	1,667,168
10	DOE Loan Guarantee Fees and Compliance Cost	433,765
11	Vehicle Training (Internal & External)	30,000
12	Broker Fees	5,000
13	Miscellaneous Labor Expenses	35,293
14	Miscellaneous General Expenses	186,690
15	COVID-19 Costs	5,639,597
46	TOTAL	18,104,593

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			50,002,191		50,002,191
2	Steam Production Plant	337,438,440	29,848,777			367,287,217
3	Nuclear Production Plant	99,177,874	6,651,757			105,829,631
4	Hydraulic Production Plant-Conventional	14,562,339	343,733			14,906,072
5	Hydraulic Production Plant-Pumped Storage	6,534,700				6,534,700
6	Other Production Plant	108,269,058	1,655,621			109,924,679
7	Transmission Plant	152,206,389	(12,351)			152,194,038
8	Distribution Plant	348,073,979	180,864			348,254,843
9	Regional Transmission and Market Operation					
10	General Plant	40,217,969	107,860			40,325,829
11	Common Plant-Electric					
12	TOTAL	[a]1,106,480,748	38,776,261	50,002,191		1,195,259,200

B. Basis for Amortization Charges

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam	9,231.641	70 years	(20)%	4.45%	VARIOUS	17 years

13	Nuclear	5,123.071	64 years	(25)%	2.08%	VARIOUS	38 years, 7 months
14	Hydraulic	819.096	88 years	(20)%	2.52%	VARIOUS	22 years, 8 months
15	Other	3,289.276	49 years	(2)%	3.2%	VARIOUS	29 years, 4 months
16	Transmission						
17	350	405.293	85 years	0%	1.1%	SQ	63 years, 11 months
18	352	215.258	85 years	(25)%	1.51%	R2.5	71 years, 9 months
19	353	2,544.571	52 years	(25)%	2.13%	R0.5	50 years, 9 months
20	354	1,066.077	65 years	(25)%	1.82%	R2	54 years, 1 month
21	355	816.817	50 years	(25)%	2.57%	R0.5	41 years, 4 months
22	356	1,600.43	50 years	(25)%	2.62%	R3	36 years, 8 months
23	357	11.857	80 years	(25)%	1.61%	R5	66 years, 6 months
24	358	25.652	55 years	(25)%	2.32%	R2	47 years
25	359	6.546	70 years	(25)%	1.8%	SQ	65 years, 1 month
26	Transmission Total	6,692.501	66 years	0%	2.24%		55 years, 3 months
27	Distribution						
28	360	155.427	70 years	0%	1.48%	SQ	62 years, 4 months
29	361	245.438	70 years	(20)%	1.63%	R2.5	58 years
30	362	1,640.149	47 years	(20)%	2.43%	R0.5	38 years, 6 months
31	364	1,161.178	47 years	(20)%	2.41%	L0	37 years, 11 months
32	365	1,368.944	40 years	(20)%	2.84%	L0	32 years, 3 months
33	366	460.312	80 years	(20)%	1.39%	S6	60 years, 9 months
34	368	1,706.53	38 years	(20)%	2.9%	R0.5	28 years
35	369	1,160.829	51 years	(20)%	2.16%	R1	37 years, 8 months
36	370	526.905	18 years	(20)%	6.11%	R0.5	13 years, 2 months
37	371	2.206	10 years	(20)%	9.88%	SQ	9 years, 6 months
38	372	0.798	10 years	(20)%	0%	SQ	4 months
39	373	890.717	26 years	(20)%	4.17%	R0.5	18 years, 2 months
40	Distribution Total	11,142.963	46 years	0%	2.7%		33 years, 7 months
41	General						
42	390	628.97	55 years	0%	1.76%	R1	40 years
43	392	367.037	8 years	20%	4.32%	VARIOUS	5 years, 2 months
44	396	29.442	7 years	20%	11.27%	L0	4 years, 9 months
45	397	437.61	18 years	0%	2.72%	L0	15 years, 5 months
46	General Total	1,463.059	22 years		2.91%		16 years, 4 months

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FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

1) The depreciable base is calculated as an average of beginning and ending plant in service balances.

2) The average remaining service life is presented as of the measurement date used in the study to compute the depreciation rates used in the current year.

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) rela before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previ
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZ	
						CURRENTLY CHARGED TO					
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	
1	VOGTLE 3 & 4 CONSTRUCTION MONITORING - DOCKET NO. 29849		5,156,008	5,156,008		ELECTRIC	107	5,156,008			
2	FUEL COST RECOVERY - DOCKET NO. 22403		4,628	4,628		ELECTRIC	928	4,628			
3	RENEWABLES AND GREEN ENERGY - DOCKET NOS. 39732, 43107, 43085, 43814, and 43985		202,658	202,658		ELECTRIC	928	202,658			
4	INTEGRATED RESOURCE PLANS - DOCKET NOS. 42641, 42310, and 44160		3,658,639	3,658,639		ELECTRIC	928	3,658,639			
5	DEMAND SIDE MANAGEMENT CERTIFICATION - DOCKET NOS. 42311, 43040, and 44161		505,352	505,352		ELECTRIC	928	505,352			
6	ALTERNATE RATE PLANS - DOCKET NO. 36989, 42516, and 44280		4,333,024	4,333,024		ELECTRIC	928	4,333,024			
7	CRSP CUSTOMER PROGRAM - DOCKET NO. 42958		7,103	7,103		ELECTRIC	928	7,103			
8			7,169	7,169		ELECTRIC	928	7,169			

	WEST FRASER & STANDARD CONCRETE PETIT - DOCKET NOS. 43689, 43690, 43688									
9	FINANCING AUTHORITY APPLICATION - DOCKET NO. 44054		3,226	3,226		ELECTRIC	928	3,226		
10	SAWNEE EMC v. GPC - DOCKET NO. 43899		305,770	305,770		ELECTRIC	928	305,770		
11	ROBINS AIR FORCE - DOCKET NO. 40161		26,619	26,619		ELECTRIC	107	26,619		
12	DOCKET ITEMS UNDER $25,000 (4 ITEMS): (APPLICATIONS FEES, LEGAL AND PROFESSIONAL SERVICES)		33,719	33,719		ELECTRIC	928	33,719		
13						0	0			
46	TOTAL		14,243,915	14,243,915				14,243,915		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   A. Electric R, D and D Performed Internally:

      1. Generation

         a. hydroelectric

            i. Recreation fish and wildlife
            ii. Other hydroelectric

         b. Fossil-fuel steam
         c. Internal combustion or gas turbine
         d. Nuclear
         e. Unconventional generation
         f. Siting and heat rejection

      2. Transmission

         a. Overhead
         b. Underground

      3. Distribution
      4. Regional Transmission and Market Operation
      5. Environment (other than equipment)
      6. Other (Classify and include items in excess of $50,000.)
      7. Total Cost Incurred

   B. Electric, R, D and D Performed Externally:

      1. Research Support to the electrical Research Council or the Electric Power Research Institute
      2. Research Support to Edison Electric Institute
      3. Research Support to Nuclear Power Groups
      4. Research Support to Others (Classify)
      5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	A. ELECTRIC UTILITY R,D&D PERFORMED INTERNALLY						
2	(1) GENERATION						
3	b. Fossil-fuel steam	Advanced Power Plant 506	508,421		506	361,335	
4		Advanced Power Plant 549			549	147,086	
5	d. Nuclear	Next Generation Nuclear R&D	10,674,291		524	10,674,291	
6	e. Unconventional Generation	Renewable, Storage, Distributed Generation	967,492		930.2	967,492	
7	(2) TRANSMISSION						
8	a. Overhead	Power Delivery Transmission Research	1,517,403		566	1,517,403	

9	(3) DISTRIBUTION	Power Delivery Distribution Research	655,603		588	655,603	
10	(5) ENVIRONMENTAL	Advanced End Use Technology	1,938,011		930.2	1,938,011	
11		Advanced Energy Systems 506	4,038,674		506	3,265,317	
12		Advanced Energy Systems 566			566	773,357	
13		Environmental Controls Technologies 506	697,378		506	698,265	
14		Environmental Controls Technologies 566			566	(887)	
15	(6) OTHER	Research Administration 930.2	1,331,724		930.2	1,078,103	
16		Research Administration 549			549	206,251	
17		Research Administration 566			566	47,370	
18	B. ELECTRIC UTILITY R,D&D PERFORMED EXTERNALLY						
19	(1) RESEARCH SUPPORT TO THE ELECTRIC						
20	POWER RESEARCH INSTITUTE	Electric Power Research Institute 506		7,795,696	506	1,113,749	
21		Electric Power Research Institute 524			524	1,690,328	
22		Electric Power Research Institute 539			539	413,712	
23		Electric Power Research Institute 549			549	1,575,495	
24		Electric Power Research Institute 566			566	696,034	
25		Electric Power Research Institute 588			588	1,170,260	
26		Electric Power Research Institute 910			910	1,136,118	
27		EPRI Hydrogen Fuel Blend Project			549	2,500,000	
28		EPRI Distribution Project		3,000,000	588	3,000,000	
29		EPRI HEMP and IEMI		50,000	566	50,000	
30	LESS COST BILLED TO OTHERS	0		(525,125)	506, 524, 549, 555	(525,125)	
31	TOTAL COMPANY COST			12,820,571		35,149,568	
32	0						

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	84,157,408		
4	Transmission	17,045,068		
5	Regional Market			
6	Distribution	63,285,901		
7	Customer Accounts	57,368,938		
8	Customer Service and Informational	12,669,204		
9	Sales	22,488,954		
10	Administrative and General	87,510,170		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	344,525,643		
12	Maintenance			
13	Production	30,055,968		
14	Transmission	23,944,341		
15	Regional Market			
16	Distribution	66,796,124		
17	Administrative and General	2,385,077		
18	TOTAL Maintenance (Total of lines 13 thru 17)	123,181,510		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	114,213,376		
21	Transmission (Enter Total of lines 4 and 14)	40,989,409		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	130,082,025		
24	Customer Accounts (Transcribe from line 7)	57,368,938		
25	Customer Service and Informational (Transcribe from line 8)	12,669,204		
26	Sales (Transcribe from line 9)	22,488,954		
27	Administrative and General (Enter Total of lines 10 and 17)	89,895,247		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	467,707,153	6,641,386	474,348,539
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			

62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	467,707,153	6,641,386	474,348,539
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	273,423,090	19,666,078	293,089,168
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	273,423,090	19,666,078	293,089,168
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Accounts Receivable	4,038,288	187,468	4,225,756
80	Printing and Reproduction	1,231,266		1,231,266
81	General Shops Expenses	1,208,642		1,208,642
82	Other Clearing Accounts	276,048		276,048
83	Jobbing Work in Progress	2,696,169		2,696,169
84	Civil, Political, and Related Expenses	1,119,410		1,119,410
85	Other Non-Operating Expenses	16,953,698	1,945,097	18,898,795
86	All Other General Accounts	15,312,026		15,312,026
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	42,835,547	2,132,565	44,968,112
96	TOTAL SALARIES AND WAGES	783,965,790	28,440,029	812,405,819

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	[a]0	2,781,104	18,817,069	21,779,636
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(703,689)	(531,906)	(519,421)	(73,752)
4	Transmission Rights	90,477	523,668	752,907	941,520
5	Ancillary Services	525	1,897	2,993	3,188
6	Other Items (list separately)				
7	Balancing Operating Reserve	1,547	3,462	6,037	6,217
8	Administrative Fees	3,181	10,511	29,157	31,746
9	Miscellaneous	118	3,775	7,356	7,808
46	TOTAL	(607,841)	2,792,511	19,096,098	[b]22,696,363

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

Line Nos. 1-9 Columns: b-e

These amounts represent Georgia Power's portion of the RTO settlement statements received by Southern Company Services. RTO settlement statements received by Southern Company Services include amounts allocated to Alabama Power, Georgia Power, Florida Power and Light Company (as surviving company after merger with Gulf Power), Mississippi Power, and Southern Power Company.

(b) Concept: IsoOrRtoSettlements

The amounts presented agree with settlement statements received and do not include adjustments from other periods that might have been booked.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	0	—	[a]0	103,664	MW-Months	8,355,681
2	Reactive Supply and Voltage	6,363	MWhs	700,000	52,845	MW-Months	5,813,198
3	Regulation and Frequency Response	0	—	0	20,161	MW-Months	974,159
4	Energy Imbalance	33,217	MWhs	1,940,154	12,274	MWhs	1,025,305
5	Operating Reserve - Spinning	0	—	0	15,897	MW-Months	1,336,101
6	Operating Reserve - Supplement	0	—	0	15,897	MW-Months	1,336,101
7	Other	[b]50968	MWhs	3,854,239	22,468	MWhs	2,379,172
8	Total (Lines 1 thru 7)	90,548		6,494,393	243,206		21,219,717

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount

Line No. 1-6 column: d, g

The Southern Company electric operating companies (Alabama Power Company, Georgia Power Company, and Mississippi Power Company) collectively are the Transmission Provider under the Open Access Transmission Tariff (OATT) and operate their transmission facilities as a single integrated system. The ancillary services, sales, and purchase amounts associated with transmission service provided under the OATT are the total values for the Southern Company electric operating companies.

(b) Concept: AncillaryServicesPurchasedNumberOfUnits

Line No. 7 column: b,d,e,g

Generator Imbalance Service (Schedule 10) offered under the OATT.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: Georgia Power Company									
1	January	[a]30,635	18	7	112	500	1,066	850		28,107
2	February	29,810	9	7	112	539	1,066	850		27,243
3	March	27,450	13	8	112	551	1,066	850		24,871
4	Total for Quarter 1				336	1,590	3,198	2,550		80,221
5	April	23,123	25	17	53	433	2,098			22,539
6	May	30,640	19	16	78	796	2,018			27,748
7	June	34,472	15	16	102	935	2,018			31,417
8	Total for Quarter 2				233	2,164	6,134			81,704
9	July	34,910	6	16	97	550	3,471		1,555	29,237
10	August	33,729	15	16	96	519	3,471		1,377	28,266
11	September	33,426	22	15	85	873	3,471		1,035	27,962
12	Total for Quarter 3				278	1,942	10,413		3,967	85,465
13	October	24,587	20	8	77	325	2,721		693	20,771
14	November	28,315	18	7	109	316	2,721		662	24,507
15	December	35,069	24	8	160	305	2,721		2,211	29,672
16	Total for Quarter 4				346	946	8,163		3,566	74,950
17	Total				1,193	6,642	27,908	2,550	7,533	322,340

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

The Southern Company electric operating companies (Alabama Power Company, Georgia Power Company, and Mississippi Power Company) collectively are the Transmission Provider under the Open Access Transmission Tariff and operate their transmission facilities as a single integrated system. Values shown correspond to the total transmission system peak loads on the Southern Company transmission system. Estimated load values are shown. The estimated loads are based on the customer's peak demand for previous month. Values are also based on telemetered load values using preliminary peak day and hour. The peak day and hour could change when actual loads are available.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Enter System									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2023-04-20	Year/Period of Report End of: 2022/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	85,956,486
3	Steam	(a) 12,639,389	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear	16,212,200	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,445,555
5	Hydro-Conventional	1,558,965	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	298,479	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	(b) 117,215
7	Other	27,880,657	27	Total Energy Losses	(c) 3,534,078
8	Less Energy for Pumping	373,342	27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	58,216,348	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	92,053,334
10	Purchases (other than for Energy Storage)	33,637,632			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	16,387,588			
13	Delivered	16,188,234			
14	Net Exchanges (Line 12 minus line 13)	199,354			
15	Transmission For Other (Wheeling)				
16	Received	33,547,643			
17	Delivered	33,016,491			
18	Net Transmission for Other (Line 16 minus line 17)	531,152			
19	Transmission By Others Losses	(531,152)			
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	92,053,334			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2023-04-20	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SteamGeneration
Resubmission - Update to Steam MegaWatt Hours and subsequent totals
(b) Concept: InternalUseEnergy
Resubmission - Update toEnergy Used by the Company (Electric Dept Only, Excluding Station Use) MegaWatt Hours and subsequent totals
(c) Concept: EnergyLosses
Resubmission - Update to Total Energy Losses MegaWatt Hours and subsequent totals

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Georgia Power Company					
29	January	[a]8,273,804	409,061	13,945	18	6
30	February	6,922,950	290,922	13,677	9	6
31	March	6,983,527	242,523	12,544	14	7
32	April	6,643,545	223,841	11,911	25	15
33	May	7,704,549	225,420	15,001	19	15
34	June	8,730,940	245,009	17,074	15	15
35	July	9,149,601	196,373	16,372	6	15
36	August	8,798,524	184,184	16,057	2	15
37	September	7,563,729	98,022	15,181	22	14
38	October	6,684,041	101,490	11,355	20	7
39	November	6,834,189	106,099	12,961	18	6
40	December	7,763,935	122,611	15,674	24	7
41	Total	92,053,334	2,445,555			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: EnergyActivity

Resubmission - Update to all month's Total Monthly Energy

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: BOULEVARD (RETIRED)	Plant Name: BOWEN	Plant Name: FORT BENNING	Plant Name: FORT GORDON	Plant Name: FORT STEWART	Plant Name: FORT VALLEY STATE UNIVERSITY	Plant Name: [(a) (b)] HATCH	Plant Name: KING'S BAY
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	COMBUSTION TURBINE	STEAM	SOLAR PROJECT	SOLAR PROJECT	SOLAR PROJECT	SOLAR PROJECT	NUCLEAR	SOLA PROJEC
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	OUTDOOR	CONVENTIONAL	OUTDOOR	OUTDOOR	OUTDOOR	OUTDOOR	0	OUTDOO
3	Year Originally Constructed	1970	1971	2015	2016	2016	2022	1974	201
4	Year Last Unit was Installed	1970	1975	2015	2016	2016	2022	1978	201
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	15.60	3,499.00	30.01	30.00	30.00	10.80	926.00	30.1
6	Net Peak Demand on Plant - MW (60 minutes)	3	3,361	30	31	32	11	905	3
7	Plant Hours Connected to Load	2	8,580	4,057	4,044	3,984	3,764	8,759	4,08
8	Net Continuous Plant Capability (Megawatts)	0	0	30	30	30	11	0	3
9	When Not Limited by Condenser Water	14	3,120	0	0	0	0	881	

10	When Limited by Condenser Water	0	0	0	0	0	0	0	
11	Average Number of Employees	0	425	0	0	0	0	959	
12	Net Generation, Exclusive of Plant Use - kWh	(47,000)	8,476,152,000	52,960,000	57,016,000	53,215,000	21,879,000	[9]7,293,750,885	56,817,00
13	Cost of Plant: Land and Land Rights		27,893,122					599,935	
14	Structures and Improvements		543,469,703					206,248,160	
15	Equipment Costs		4,432,168,364	67,299,135	67,097,840	67,068,251	22,630,070	1,146,996,126	67,262,31
16	Asset Retirement Costs		785,148,432					184,316,475	
17	Total cost (total 13 thru 20)		5,788,679,621	67,299,135	67,097,840	67,068,251	22,630,070	1,538,160,696	67,262,31
18	Cost per KW of Installed Capacity (line 17/5) Including		1,654.3811	2,242.5570	2,236.5947	2,235.6084	2,095.3769	1,661.0807	2,230.182
19	Production Expenses: Oper, Supv, & Engr	2,734	10,289,335	16,562	15,695	15,691	676	46,717,234	16,54
20	Fuel	10,092	355,472,334					57,592,751	
21	Coolants and Water (Nuclear Plants Only)							4,995,233	
22	Steam Expenses	466	13,801,190	22,568	10,544	10,716	108,832	7,415,244	71,95
23	Steam From Other Sources								
24	Steam Transferred (Cr)								
25	Electric Expenses		10,088,470					104,379	
26	Misc Steam (or Nuclear) Power Expenses	50,878	20,118,885	41,836	49,604	41,916		57,834,711	48,41
27	Rents							324,350	
28	Allowances		5,641						
29		45,219	7,262,327	61,580	61,581	61,580		15,017,418	61,58

	Maintenance Supervision and Engineering								
30	Maintenance of Structures	11,977	12,647,066	2,755	289	266	1,224	1,902,180	31
31	Maintenance of Boiler (or reactor) Plant		52,196,253					5,353,664	
32	Maintenance of Electric Plant	6,103	4,941,335	139,725	187,005	216,576	19,335	6,224,269	1,011,20
33	Maintenance of Misc Steam (or Nuclear) Plant	6,144	3,034,651	35,038	3,524	46,391		6,632,909	46,78
34	Total Production Expenses	133,613	489,857,487	320,064	328,242	393,136	130,067	210,114,342	1,256,78
35	Expenses per Net kWh	(2.8428)	0.0578	0.0060	0.0058	0.0074	0.0059	0.0288	0.022

35	Plant Name	BOULEVARD (RETIRED)	BOWEN	BOWEN	FORT BENNING	FORT STEWART	HATCH	HATCH	KING'S BAY	MCDONOUGH NO. 3	MCDONOU NO. 3
36	Fuel Kind	Oil	Coal	Oil	0	0	0	Nuclear	0	Gas	Oil
37	Fuel Unit	bbl	T	bbl	0	0	0	g	0	Mcf	bbl
38	Quantity (Units) of Fuel Burned	29	3,552,139	39,519				1,220,102		383	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6	11,843	6				64,549,411		1,029	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	56.897	97.838	161.404				47.206		2,492.422	133
41	Average Cost of Fuel per Unit Burned	56.897	97.838	161.404				47.206		2,492.422	133
42	Average Cost of Fuel Burned per Million BTU	9.734	4.131	27.747				0.731		2,422.836	22
43	Average Cost of Fuel Burned per kWh Net Gen	(0.035)	0.041					0.008		6.407	
44	Average BTU per kWh Net Generation	(3,553.191)	9,925.930					10,797.860		2,644.295	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Plant Vogtle, Plant Hatch, and Plant Wansley are jointly owned with Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton.

(b) Concept: PlantName

12.

a) After nuclear fuel is placed in the reactor, the cost of fuel is amortized on the basis of quantity of heat produced, therefore matching the cost of the fuel with the power produced.

b) Uranium: lbs
Conversion: Kilograms of uranium (kgU)
Enrichment: Separative work units (SWU)
Fabrication: Assemblies

c) Type of fuel Used: Uranium
Enrichment: 4-5%
Fuel Array: 10 x 10
Fuel Assemblies: 560 Assemblies per Unit
Active Length of Fuel Assembly: Approximately 12.5 feet
Fuel Rods per Assembly: 96
Reactors: Two Boiling Water Reactors (BWRs) manufactured by General Electric Company

(c) Concept: PlantName

Plant Scherer is jointly owned with Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, the City of Dalton, Florida Power and Light Company, and Jacksonville Electric Authority.

(d) Concept: PlantName

Plant Vogtle, Plant Hatch, and Plant Wansley are jointly owned with Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton.

(e) Concept: PlantName

12.

a) After nuclear fuel is placed in the reactor, the cost of fuel is amortized on the basis of quantity of heat produced, therefore matching the cost of the fuel with the power produced.

b) Uranium: lbs
Conversion: Kilograms of uranium (kgU)
Enrichment: Separative work units (SWU)
Fabrication: Assemblies

c) Type of fuel Used: Uranium
Enrichment: 4-5%
Fuel Array: 17 x 17
Fuel Assemblies: 193 Assemblies per Unit
Active Length of Fuel Assembly: Approximately 12 feet
Fuel Rods per Assembly: 264
Reactors: Two Pressurized Water Reactors (PWRs) manufactured by Westinghouse Electric Company

(f) Concept: PlantName

Plant Vogtle, Plant Hatch, and Plant Wansley are jointly owned with Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton.

(g) Concept: NetGenerationExcludingPlantUse

Resubmission - Update to Net Generation, Exclusive of Plant Use - KWh

(h) Concept: NetGenerationExcludingPlantUse

Resubmission - Update to Net Generation, Exclusive of Plant Use - KWh

(i) Concept: NetGenerationExcludingPlantUse

Resubmission - Update to Net Generation, Exclusive of Plant Use - KWh

(j) Concept: NetGenerationExcludingPlantUse

Resubmission - Update to Net Generation, Exclusive of Plant Use - KWh

(k) Concept: NetGenerationExcludingPlantUse

Resubmission - Update to Net Generation, Exclusive of Plant Use - KWh

(l) Concept: ExpensesPerNetKilowattHour

Resubmission - Update to Expenses per Net KWh

(m) Concept: ExpensesPerNetKilowattHour

Resubmission - Update to Expenses per Net KWh

(n) Concept: ExpensesPerNetKilowattHour

Resubmission - Update to Expenses per Net KWh

(o) Concept: ExpensesPerNetKilowattHour
Resubmission - Update to Expenses per Net KWh
(p) Concept: ExpensesPerNetKilowattHour
Resubmission - Update to Expenses per Net KWh
(q) Concept: ExpensesPerNetKilowattHour
Resubmission - Update to Expenses per Net KWh

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 1951 Plant Name: SINCLAIR DAM	FERC Licensed Project No. 2177 Plant Name: GOAT ROCK	FERC Licensed Project No. 2177 Plant Name: NORTH HIGHLANDS	FERC Licensed Project No. 2177 Plant Name: OLIVER DAM	FERC Licensed Project No. 2237 Plant Name: MORGAN FALLS	FERC Licensed Project No. 2336 Plant Name: LLOYD SHOALS	FERC Licensed Project No. 2354 Plant Name: MATHIS-TERRORA	L P Pl T
1	Kind of Plant (Run-of-River or Storage)		Storage	Run-of-River	Run-of-River	Run-of-River	Run-of-River	Storage	Storage	R
2	Plant Construction type (Conventional or Outdoor)		Conventional	Conventional	Conventional	Conventional	Conventional	Conventional	Conventional	C
3	Year Originally Constructed		1953	1912	1963	1959	1903	1911	1925	
4	Year Last Unit was Installed		1953	2005	1963	1959	1923	1916	1925	
5	Total installed cap (Gen name plate Rating in MW)		45.00	39.00	29.60	60.00	16.80	14.40	16.00	
6	Net Peak Demand on Plant-Megawatts (60 minutes)		44	33	38	58	12	18	18	
7	Plant Hours Connect to Load		7,932	8,460	7,583	7,388	8,676	8,435	5,145	
8	**Net Plant Capability (in megawatts)**									
9	(a) Under Most Favorable Oper Conditions		44	40	35	59	11	23	17	
10	(b) Under the Most Adverse Oper Conditions		44	39	34	58	11	23	17	
11										

	Average Number of Employees									
12	Net Generation, Exclusive of Plant Use - kWh		117,931,000	142,423,000	124,103,000	209,722,000	35,419,000	69,329,000	46,592,000	15
13	**Cost of Plant**									
14	Land and Land Rights		2,130,875	586,559	204,939	861,147	2,940	882,269	101,777	
15	Structures and Improvements		3,306,722	2,345,647	2,478,519	2,690,521	1,137,816	2,724,209	2,009,222	
16	Reservoirs, Dams, and Waterways		10,282,395	10,389,709	6,795,453	6,798,099	6,699,760	12,847,000	16,078,145	
17	Equipment Costs		8,764,287	21,361,811	4,977,293	9,875,741	12,204,913	12,773,958	43,243,602	2
18	Roads, Railroads, and Bridges		41,522	52,308	37,614	349,257	36,694	48,818	134,365	
19	Asset Retirement Costs		139,730	65,247	280,817	516,482	283,642	154,044	448,355	
20	Total cost (total 13 thru 20)		24,665,531	34,801,281	14,774,635	21,091,247	20,365,765	29,430,298	62,015,466	3
21	Cost per KW of Installed Capacity (line 20 / 5)		548.1	892.3	499.1	351.5	1,212.2	2,043.8	3,876.0	
22	**Production Expenses**									
23	Operation Supervision and Engineering		323,968	113,158	500,431	570,950	306,973	67,677	41,174	
24	Water for Power			435,582	253,143	461,751	137,356			
25	Hydraulic Expenses		(3,253)	(619)	(475)	(6,680)	(270)	(1,004)	(257)	
26	Electric Expenses		63,826	5,842	3,685	(1,774)	863,387	51,738	13,351	
27	Misc Hydraulic Power Generation Expenses		61,504	38,115	118,173	79,477	102,512	33,335	16,154	
28	Rents									
29	Maintenance Supervision and Engineering		11,409	9,776	7,503	15,205	3,229	3,641	4,061	
30	Maintenance of Structures		1,886,284	3,293	502	6,664	150,735	196,089	125,534	
31			825,813	92,402	182,605	293,649	1,350,209	473,629	42,975	

	Maintenance of Reservoirs, Dams, and Waterways									
32	Maintenance of Electric Plant		74,523	344,272	36,735	157,652	85,864	524,449	180,731	
33	Maintenance of Misc Hydraulic Plant		17,600	18,423	21,415	21,965	66,162	9,232		
34	Total Production Expenses (total 23 thru 33)		3,261,674	1,060,244	1,123,717	1,598,859	3,066,157	1,358,786	423,723	
35	Expenses per net kWh	0.0000	0.0277	0.0074	0.0091	0.0076	0.0866	0.0196	0.0091	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: ROCKY MOUNTAIN	FERC Licensed Project No. 2413 Plant Name: WALLACE DAM
1	Type of Plant Construction (Conventional or Outdoor)	[a] 0	SEMI-OUTDOOR
2	Year Originally Constructed	1995	1979
3	Year Last Unit was Installed	1995	1980
4	Total installed cap (Gen name plate Rating in MW)	278	209
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	260	210
6	Plant Hours Connect to Load While Generating	3,196	1,694
7	Net Plant Capability (in megawatts)	190	213
8	Average Number of Employees		
9	Generation, Exclusive of Plant Use - kWh	173,585,304	124,894,000
10	Energy Used for Pumping	224,899,915	148,442,000
11	Net Output for Load (line 9 - line 10) - Kwh	(51,314,611)	(23,548,000)
12	**Cost of Plant**		
13	Land and Land Rights	1,959,330	17,737,937
14	Structures and Improvements	40,002,932	25,660,965
15	Reservoirs, Dams, and Waterways	73,728,092	56,791,448
16	Water Wheels, Turbines, and Generators	46,240,040	50,532,354
17	Accessory Electric Equipment	12,935,274	8,579,802
18	Miscellaneous Powerplant Equipment	4,287,133	5,456,988
19	Roads, Railroads, and Bridges	3,116,744	1,295,708
20	Asset Retirement Costs		59,914
21	Total cost (total 13 thru 20)	182,269,545	166,115,116
22	Cost per KW of installed cap (line 21 / 4)	655.6	794.8

23	**Production Expenses**		
24	Operation Supervision and Engineering	2,892,248	540,571
25	Water for Power		
26	Pumped Storage Expenses		(4,588)
27	Electric Expenses		622,834
28	Misc Pumped Storage Power generation Expenses	539,128	203,808
29	Rents		28,984
30	Maintenance Supervision and Engineering		47,663
31	Maintenance of Structures		328,913
32	Maintenance of Reservoirs, Dams, and Waterways		382,104
33	Maintenance of Electric Plant		335,243
34	Maintenance of Misc Pumped Storage Plant		19,669
35	Production Exp Before Pumping Exp (24 thru 34)	3,431,376	2,505,201
36	Pumping Expenses		
37	Total Production Exp (total 35 and 36)	3,431,376	2,505,201
38	Expenses per kWh (line 37 / 9)	0.0198	0.0201
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0	0

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantConstructionType
Rocky Mountain is jointly owned with Oglethorpe Power Corporation.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumpec than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, anc statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Pa
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, i the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)	
1	Hydro:										
2	Burton (A)	1927	8.10	8.00	22,751,000	15,133,482	2,105,791	31,748		389,070	
3	Nacoochee (A)	1926	4.80	6.00	16,005,000	8,166,312	1,637,178	15,525		139,912	
4	Flint River (B)	1921	5.40	7.00	36,836,000	24,841,981	3,216,354	791,547		527,449	
5	Estatoah - Retired (C)		0.20	0.00	0	75	305,690	280		574	
6	Langdale - Retired (D)	1907	1.00	0.00	0	2,707	1,816,188	1,749		467,919	
7	Riverview - Retired (E)	1918	0.50	0.00	0	757	1,254,446	1,831		4,368	
8	Solar:										
9	[a] Various		18.50	0.00	30,033,480	47,877,384	2,480,761	86,762		571,686	
10	(A) Licensed Project Number 2354.										
11	(B) Licensed Project Number 1218.										
12	(C) Approximately 1928. Record of Owners inadeq.										
13	(D) Licensed Project Number 2341.										
14	(E) Licensed Project Number 2350.										

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantName
Various Solar consists of Dalton, University of Georgia, Falcons Solar Projects, Tri-County Solar Projects, Guyton, Comer, Waynesboro, and LaGrange.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

ENERGY STORAGE OPERATIONS (

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and locatior
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) s
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the incor
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)
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Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilov required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report s
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; c indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of con
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if y structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in colum
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, g other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operati matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by th is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determ
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	CO
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			L
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	500 KV STEEL STRUCTURES									
2	BOWEN	NORCROSS 500 KV LN	500.00	500.00	Steel Towers	57.30	11.73	1	1113 ACSR	2
3	BOWEN	TVA 500 KV LN	500.00	500.00	Steel Towers	43.04	0.00	1	1113 ACSR	
4	BOWEN	UNION CITY #1 500 KV LN	500.00	500.00	Steel Towers	48.82	0.00	1	1113 ACSR	2
5	BOWEN	UNION CITY #2 500 KV LN	500.00	500.00	Steel Towers	57.63	0.00	1	1113 ACSR	
6	FARLEY	NORTH TIFTON 500 KV LN	500.00	500.00	Steel Towers	96.33	0.00	1	1113 ACSR	1
7	FORTSO	N TIFTON 500 KV LN	500.00	500.00	Steel Towers	116.51	0.00	1	1113 ACSR	5
8	HATCH	OFFERMAN-FLA ST LN 500 KV L	500.00	500.00	Steel Towers	88.67	0.00	1	1113 ACSR	2
9	HATCH	THALMANN-DUVAL 500 KV LN	500.00	500.00	Steel Towers	105.91	0.00	1	1113 ACSR	3
10	NORCROSS	OCONEE LN 500 KV LN	500.00	500.00	Steel Towers	79.10	0.00	1	1113 ACSR	5
11	SCHERER	WALLACE DAM 500 KV LN	500.00	500.00	Steel Towers	53.43	0.00	1	1113 ACSR	2
12	PLANT VOGTLE	KLONDIKE 500KV LN					0.00			
13	PLT SCHERER						0.00			

		O'HARA 500KV LN								
14	VOGTLE	MCINTOSH-THALMANN 500 KV LN	500.00	500.00	Steel Towers	221.21	0.00	1	1113 ACSR	6
15	VOGTLE	WADLEY 500 KV LN	500.00	500.00	Steel Towers	43.55	0.00	1	1113 ACSR	
16	WANSLEY	OHARA 500 KV LN	500.00	500.00	Steel Towers	50.78	0.00	1	1113 ACSR	
17	WADLEY	WALLACE DAM 500 KV LN	500.00	500.00	Steel Towers	56.98	0.00	1	1113 ACSR	
18	MCGRAU FORD	MOSTELLER SPRINGS	500.00	500.00	Steel Towers	34.50	0.00	1	1113 ACSR	1
19	VOGTLE BUS #1	VOGTLE 3&4 BUS #3	500.00	500.00	Steel Towers	0.19	0.00	1	1113 ACSR	
20	VOGTLE BUS #2	VOGTLE 3&4 BUS #4	500.00	500.00	Steel Towers	0.19	0.00	1	1113 ACSR	
21	THOMSON	VOGTLE 500 KV LINE	500.00	500.00	Steel Towers	55.21	0.00	1	1113 ACSR	
22	230 KV WOOD STRUCTURES									
23	YATES	BONAIRE	230.00	230.00	Wood H-Frame	101.38	0.00	1	1033 ACSR	
24	MORGANVILLE	TVA 230KV LN	161.00	230.00	Wood H-Frame	0.13	0.00	1	477 ACSR	
25	S BAINBRIDGE	FLA ST LN 230 KV LN	230.00	230.00	Wood H-Frame	0.09	0.00	1	1033 ACSR	
26	230 KV STEEL STRUCTURES									
27	AUGUSTA	NEWSPRINT 230 KV LOOP LN	230.00	230.00	Steel H-Frame	8.68	0.00	1	1351 ACSR	
28	AUSTIN DRIVE	SCOTTDALE 230 KV LN	230.00	230.00	Steel Pole	11.69	0.00	1	1351 ACSR	
29	COBB PLACE	WOODSTOCK 230 KV LN	230.00	230.00	Steel Pole	10.13	0.00	1	1351 ACSR	
30	BOAT ROCK	ADAMSVILLE 230 KV LN	230.00	230.00	Steel Single Pole	7.23	0.00	1	1033 ACSR	
31	BONAIRE	NORTH TIFTON 230 KV LN	230.00	230.00	Steel H-Frame	77.10	0.00	1	795 ACSR	
32	BOULEVARD	BUCKHEAD	230.00	230.00	Steel Pole	3.86	0.00	1	1351 SSAC	
33	BUCKHEAD	BULL SLUICE	230.00	230.00	Steel Pole	10.17	0.00	1	1351 ACSR	
34	BOWEN	CARTERSVILLE	230.00	230.00	Steel Tower	8.06	7.30	2	795 ACSR	
35	BOWEN	PINSON	230.00	230.00	Steel H-Frame	6.62	0.00	2	795 ACSR	
36	BOWEN	PINSON-ATLANTIC STEEL 230 K	230.00	230.00	Steel H-Frame	19.77	0.00	1	795 ACSR	
37	BRANCH	EVANS 230 LINE					0.00			
38	BRANCH		230.00	230.00		6.61	0.00	1		

		GOSHEN 230KV LN			Steel H-Frame				1351 ACSR	
39	BRANCH	PORTERDALE	230.00	230.00	Steel H-Frame	53.01	0.00	1	1351 ACSR	
40	KLONDIKE	MORROW	230.00	230.00	Steel H-Frame	20.18	0.00	1	1351 ACSR	
41	GRADY	KLONDIKE	230.00	230.00	Steel H-Frame	0.40	0.00	1	795 ACSR	
42	KLONDIKE	PORTERDALE	230.00	230.00	Steel Tower	13.43	0.00	1	1351 ACSR	
43	GRADY	KLONDIKE	230.00	230.00	Steel Tower	5.60	0.00	1	795 ACSR	
44	BRANCH	NORCROSS 230 KV LN	230.00	230.00	Steel H-Frame	77.65	0.00	1	1351 ACSR	
45	BRANCH	WINDER 230 KV LN	230.00	230.00	Steel H-Frame	66.37	0.00	1	1351 ACSR	
46	CARTERS DAM	COOSAWATTEE 230 KV LN	230.00	230.00	Steel H-Frame	0.46	0.00	1	1033 ACSR	
47	CENTER	EAST WATKINSVILLE 230				0.00	0.00			
48	E DALTON	NORCROSS 230 KV LN	230.00	230.00	Steel Pole	0.26		1	1351 ACSR	
49	ALPHARETTA	OCEE	230.00	230.00	Steel H-Frame	5.46	0.00	1	1351 ACSR	
50	CARTERS DAM	EAST DALTON	230.00	230.00	Steel H-Frame	19.57	0.00	1	1033 ACSR	
51	MCGRAU	FORD LOOP	230.00	230.00	Steel H-Frame	1.97	1.65	2	2-795 ACSR	
52	NELSON	OCEE	230.00	230.00	Steel H-Frame	30.61	0.00	1	1033 ACSR	
53	NORCROSS	OCEE	230.00	230.00	Steel H-Frame	10.86	0.00	1	1033 ACSR	
54	E. DALTON	OOSTANAULA-PINSON 230KV	230.00	230.00	Steel H-Frame	11.41	0.00	1	795 ACSR	
55	EVANS	DUM JON 230 KV LN	230.00	230.00	Steel Pole	34.11		1	1351 ACSR	
56	FARLEY	SOUTH BAINBRIDGE 230 KV LN	230.00	230.00	Steel H-Frame	53.40	0.00	1	1351 ACSR	
57	FORREST RD	S MACON 230KV LN				0.00	0.00			
58	FORTSON	EAST COLUMBUS 230 KV				0.00	0.00			
59	GAINESVILLE	CENTER 230 KV LN	230.00	230.00	Steel H-Frame	22.91		1	1351 ACSR	
60	GAINESVILLE	CENTER 230 KV LN	230.00	230.00	Steel Pole	9.46		1	795 ACSR	
61	GOAT ROCK	BONAIRE 230 KV LN	230.00	230.00	Steel H-Frame	9.93	0.00	1	795 ACSR	
62	GOAT ROCK	NORTH TIFTON 230 KV LN	230.00	230.00	Steel H-Frame	9.93	0.00	1	795 ACSR	

63	GOAT ROCK	1ST AVE COLS 230 KV LN	230.00	230.00	Steel H-Frame	10.67	0.00	2	795 ACSR	
64	GOAT ROCK	1ST AVE COLUMBUS #2 230 KV	230.00	230.00	Steel Tower	0.00	0.92	2	795 ACSR	
65	GOAT ROCK	1ST AVE COLUMBUS #2 230 KV	230.00	230.00	Steel H-Frame	9.74	0.00	1	1351 ACSR	
66	SOUTH AUGUSTA	SCE&G (GRANITEVILLE) 230KV	230.00	230.00	Concrete Pole	5.13	0.00	1	1351 ACSR	
67	GOSHEN	SOUTH AUGUSTA 230 KV LN	230.00	230.00	Steel Pole	14.83	0.00	1	1351 ACSR	
68	GOSHEN	VOGTLE-WADLEY 230 KV LN	230.00	230.00	Steel H-Frame	47.96	0.00	1	795 ACSR	
69	GRADY	WABASH-BOULEVARD 230 KV LN	230.00	230.00	Steel Pole	3.38	0.00	1	1351 AAC	
70	GRADY	WABASH-BOULEVARD 230 KV LN	230.00	230.00	Steel Pole	3.69	0.00	1	1351 ACSR	
71	HAMMOND	ALABAMA 230 KV LN	230.00	230.00	Steel H-Frame	11.15	0.00	1	1033 ACSR	
72	HAMMOND	BOWEN NORTH 230 KV LN				0.00	0.00			
73	HAMMOND	BOWEN SOUTH 230 KV LN	230.00	230.00	Steel H-Frame	30.28	0.00	1	1351 ACSR	
74	HAMMOND	BREMEN 230 KV LN	230.00	230.00	Steel H-Frame	51.62	0.00	1	795 ACSR	5
75	HAMMOND	ROCK SPRINGS 230 KV LN	230.00	230.00	Steel H-Frame	83.39	0.00	1	1351 ACSR	
76	HATCH	OFFERMAN 230KV LN				0.00	0.00			
77	KINGSLAND	FLA POWER & LIGHT 230 KV LN	230.00	230.00	Steel H-Frame	4.18	0.00	1	1351 ACSR	
78	MCDONOUGH	EAST POINT 230 KV LN	230.00	230.00	Steel Tower	12.35	12.38	1	1351 ACSR	
79	MCDONOUGH	NORTHWEST #1 230 KV LN	230.00	230.00	Steel Tower	4.59	0.00	1	1351 ACSR	3
80	MCDONOUGH	NORTHWEST #2 230 KV LN	230.00	230.00	Steel Tower	0.00	4.58	1	1351 ACSR	
81	MCDONOUGH	PEACHTREE-BLVD DC 230 KV LN	230.00	230.00	Steel Tower	12.58	0.00	1	1351 ACSR	4
82	MITCHELL	N TIFTON 230 KV LN	230.00	230.00	Steel H-Frame	35.53	0.00	1	795 ACSR	
83	MITCHELL	SLAPPEY DRIVE 230 KV	115.00	230.00	Steel H-Frame	0.00	0.00	1	1351 ACSR	
84	MORROW	ALABAMA STATE LINE 230 KV L	230.00	230.00	Steel H-Frame	32.90	0.00	1	1351 ACSR	
85	MORROW		230.00	230.00	Steel Tower	8.42	3.25	2	1351 ACSR	

		ALABAMA STATE LINE 230 KV L								
86	MORROW	ALABAMA STATE LINE 230 KV L	230.00	230.00	Steel H-Frame	23.38	0.00	1	1351 ACSR	
87	MORROW	GRADY 230 KV LN	230.00	230.00	Steel Tower	0.00	9.60	1	795 ACSR	
88	MORROW	WINDER 230 KV LN	230.00	230.00	Steel H-Frame	6.63	0.00	1	1622 ACSR	
89	MORROW	WINDER 230 KV LN	230.00	230.00	Steel H-Frame	38.62	0.00	1	795 ACSR	
90	N TIFTON	FLA ST LN 230 KV LN	230.00	230.00	Steel H-Frame	64.64	0.00	1	1033 ACSR	
91	NORCROSS	MOR FALL-NO MARIETTA 230 KV	230.00	230.00	Steel Pole	1.14	0.00	1	1351 ACSR	
92	NORCROSS	MOR FALL-NO MARIETTA 230 KV	230.00	230.00	Steel Tower	25.36	0.00	1	1351 ACSR	
93	NORCROSS	SCOTTDALE-BLVD 230 KV LN	230.00	230.00	Steel Pole	13.29	0.00	1	1351 ACSR	
94	NORCROSS	SCOTTDALE-BLVD 230 KV LN	230.00	230.00	Steel Tower	23.69	0.00	2	1351 ACSR	
95	OHARA	SOUTH GRIFFIN 230 KV LN	230.00	230.00	Steel H-Frame	2.03	0.00	1	1033 ACSR	
96	OFFERMAN	W BRUNSWICK #1 230 KV LN	230.00	230.00	Steel H-Frame	39.22	0.00	1	1033 ACSR	
97	OFFERMAN	WEST BRUNSWICK 230 KV LN				0.00	0.00			
98	PARKAIRE	PERIMETER CENTER 230 KV LN	230.00	230.00	Steel Pole	6.08	0.00	1	1351 ACSR	
99	PERIMETER CENTER	JOHNSON FY-DERING CIR	230.00	230.00	Steel Pole	7.21	0.00	1	1351 ACSR	
100	PERIMETER CENTER	JOHNSON FY-DERING CIR	230.00	230.00	UG Duct	0.20	0.00	1	3000 XLPE	
101	E DALTON	ROCK SPRINGS-TVA 230 KV LN	230.00	230.00	Steel H-Frame	27.90	0.00	1	1351 ACSR	
102	E DALTON	ROCK SPRINGS 230 KV LN	230.00	230.00	Steel H-Frame	15.35	0.00	1	1351 ACSR	
103	RUSSELL DAM	E. WATKINSVILLE 230 KV LN	230.00	230.00	Steel Pole	7.81	0.00	1	795 ACSR	
104	RUSSELL DAM	E. WATKINSVILLE 230 KV LN	230.00	230.00	Steel H-Frame	62.29	0.00	1	1351 ACSR	
105	S BAINBRIDGE	FLA ST LN 230 KV LN	230.00	230.00	Steel H-Frame	32.72	0.00	1	1033 ACSR	
106	SOUTH AUGUSTA	15TH ST 230 KV	115.00	230.00	Steel Pole	1.23	0.00	1	1351 ACSR	
107	JONESBORO	STOCKBRIDGE 230KV	230.00	230.00	Steel Pole	5.12	0.00	2	1351 ACSR	

108	SOUTHALL	WINDER 230KV LN				0.00	0.00			
109	STATESBORO	SAVANNAH 230 KV LN	230.00	230.00	Steel H-Frame	16.06	0.00	1	1033 ACSR	
110	UNION CITY	EAST POINT #1 230 KV LN	230.00	230.00	Steel Tower	11.04	0.00	1	1590 ACSR	
111	UNION CITY	EAST POINT #2 230 KV LN	230.00	230.00	Steel Tower	4.54	6.60	1	1590 ACSR	
112	UNION CITY	SOUTH GRIFFIN 230 KV LN	230.00	230.00	Steel H-Frame	2.01	0.00	1	1033 ACSR	
113	VIDALIA	W BRUNSWICK 230 KV LN	230.00	230.00	Steel H-Frame	100.54	0.00	1	1033 ACSR	
114	VILLA RICA	EAST POINT 230 KV LN	230.00	230.00	Steel H-Frame	30.56	0.00	1	1351 ACSR	
115	WADLEY	WADLEY VIDALIA #2 230 KV LN	230.00	230.00	Steel H-Frame	46.13	0.00	1	1351 ACSR	
116	WADLEY	WADLEY VIDALIA #1 230 KV LN	230.00	230.00	Steel H-Frame	46.16	0.00	1	1033 ACSR	
117	WALLACE DAM	EATONTON 230 KV LN	230.00	230.00	Steel H-Frame	15.63	0.00	1	1351 ACSR	
118	WEST BRUNSWICK	KINGSLAND 230 KV LN	230.00	230.00	Steel H-Frame	35.96	0.00	1	1351 ACSR	
119	WEST BRUNSWICK	MCMANUS 230 KV LN	230.00	230.00	Steel H-Frame	6.21	0.00	1	1351 ACSR	
120	YATES #5	YATES #6 & #7 230 KV LN	230.00	230.00	Steel H-Frame	1.40	0.00	1	1033 ACSR	
121	YATES	BONAIRE 230 KV LN	230.00	230.00	Steel H-Frame	11.07	0.00	1	1033 ACSR	
122	YATES	MORROW 230 KV LN	230.00	230.00	Steel Tower	11.67	0.00	2	1351 ACSR	
123	YATES	MORROW 230 KV LN	230.00	230.00	Steel H-Frame	23.39	0.00	1	1033 ACSR	
124	MCINTOSH CT TIE 230KV	MCINTOSH CT TIE 230KV				0.00	0.00		1033 ACSR	
125	KINGSLAND	KINGS BAY #1 230 KV LN	230.00	230.00	Steel H-Frame	7.96	0.00	1	1351 ACSR	
126	COLERAIN	KINGS BAY #2 230 KV LN	230.00	230.00	Steel H-Frame	7.87	0.00	1	1351 ACSR	
127	ALPHARETTA	OLD ALABAMA RD 230 KV LN	230.00	230.00	Steel Pole	2.95	0.00	1	1622 ACSR/TW	
128	VOGTLE	SAVANNAH RIVER PLT (SCEG) 2	230.00	230.00	Steel H-Frame	3.99	0.00	1	1351 ACSR	
129	BIG SHANTY	WOODSTOCK 230 KV LN				0.00	0.00			
130	PONCE DE LEON	ROYAL ATL 230KV				0.00	0.00			
131	OLD ALA	MARTINS LANDING 230KV	230.00	230.00	Steel Pole	6.12	0.00	1	1622 ACSR/TW	
132	NORC		230.00	230.00	Steel Pole	28.27		1	1622 ACSR/TW	

		SWEET BOT-SUWANEE 230KV								
133	NORCROSS	CEDAR VILLAGE-ROYAL ATL 230	230.00	230.00	Steel Pole	9.55	0.00	1	1622 ACSR/TW	
134	W. MARIETTA	SMYRNA 230 KV LN	230.00	230.00	Steel Pole	7.15	0.00	1	1351 ACSR	
135	WINDER	SOUTH HALL 230 KV LN				0.00	0.00			
136	WINDER	GAINESVILLE 230 KV LN	230.00	230.00	Steel H-Frame	45.45	0.00	1	1033 ACSR	
137	WINDER	NORCROSS 230 KV LN	230.00	230.00	Steel H-Frame	12.11	1.22	1	1033 ACSR	
138	WINDER	NORCROSS 230 KV LN	230.00	230.00	Steel Pole	7.52		1	1622 ACSR/TW	
139	BRANCH	EVANS 230 KV LN	230.00	230.00	Steel H-Frame	72.81	0.00	1	1351 ACSR	
140	CENTER	MIDDLE FORK 230 KV LN	230.00	230.00	Steel H-Frame	26.56	0.00	1	1351 ACSR	8
141	MORROW	OHARA	230.00	230.00	Steel Pole	12.95	0.00	1	1351 ACSR	
142	THOMASTON	BARNESVILLE PRI 230 KV LN	230.00	230.00	Steel H-Frame	1.60	0.00	1	1033 ACSR	
143	ANTHONY SHOALS	RUSSELL DAM 230 KV LN	230.00	230.00	Steel H-Frame	2.88	0.00	1	1351 ACSR	
144	CARTERSVILLE	SOUTH ACWORTH 230 KV LN	230.00	230.00	Steel H-Frame	15.07	0.00	1	2-795 ACSR	2
145	CARTERSVILLE	SOUTH ACWORTH 230 KV LN	230.00	230.00	Steel Pole	6.71	0.00	1	2-795 ACSR	1
146	CARTERSVILLE	MCGRAU FORD 230 KV LN	230.00	230.00	Steel H-Frame	18.50	0.00	1	1351 ACSR	1
147	CARTERSVILLE	MCGRAU FORD 230 KV LN	230.00	230.00	Steel Tower	35.67	0.00	1	1351 ACSR	1
148	TIOGA	ELLIJAY 230 KV LN	230.00	230.00	Steel Pole	7.62	0.00	1	1622 ACSR	
149	TIOGA	ELLIJAY 230 KV LN	230.00	230.00	Steel H-Frame	5.00	0.00	1	1622 ACSR	
150	CORNISH MOUNTAIN	PORTERDALE PRI 230 KV	230.00	230.00	Steel H-Frame	7.40	0.00	1	1351 ACSR	
151	ALBANY	SOWEGA 230 KV LN	230.00	230.00	Steel Pole	8.98	0.00	1	1351 ACSR	
152	FORTSON	TALBOT COUNTY 230 KV (SONAT	230.00	230.00	Steel Pole	1.87	0.00	1	795 ACSR	
153	Augusta 15th St	South Augusta	230.00	230.00	Steel Pole	4.02	0.00	1	1351 ACSR	
154	BLANDFORD	LITTLE OGEECHEE (WHITE) 230	230.00	230.00	Steel Tower	24.38	0.00	1	1033 ACSR	
155	MCINTOSH	STATESBORO 230 KV (SAV)	230.00	230.00	Steel Tower	21.87	0.00	1	1033 ACSR	

156	MCINTOSH	STATESBORO 230 KV (SAV)	230.00	230.00	Steel H-Frame	15.73	0.00	1	1033 ACSR	
157	KRAFT	MCINTOSH (BLACK) 230 KV (SA	230.00	230.00	Steel Tower	16.23	0.00	1	1622 ACCR	
158	BLANDFORD	MCINTOSH (BLACK) 230 KV (SA	230.00	230.00	Steel Tower	8.23	0.00	1	1033 ACSR	
159	WEST MCINTOSH	MCINTOSH (BLACK) 230 KV LN	230.00	230.00	Steel Tower	0.42	0.00	1	1351 ACSR	
160	DEAN FOREST	KRAFT 230 KV (SAV)	230.00	230.00	Steel Tower	6.01	0.00	1	959 ACSS	
161	BLANDFORD	LITTLE OGEECHEE (BLACK) 230	230.00	230.00	Steel Tower	24.33	0.00	1	1033 ACSR	
162	HOMELAND	KETTLE CREEK 230 KV	230.00	230.00	Steel Pole	37.13	0.00	1	1351 ACSR	
163	MCINTOSH CC 230 KV TIE LINE	MCINTOSH CC 230 KV TIE LINE	230.00	230.00	Steel Tower	1.27	0.00	1	1351 ACSR	
164	BLANDFORD	MCINTOSH (WHITE) 230 KV (SA	230.00	230.00	Steel Tower	8.23	0.00	1	1033 ACSR	
165	DORCHESTER	LITTLE OGEECHEE 230 KV LN	230.00	230.00	Steel H-Frame	21.90	0.00	1	1351 ACSR	
166	KRAFT	MCINTOSH (WHITE) 230 KV (SA	230.00	230.00	Steel Tower	16.25	0.00	1	1033 ACSR	
167	MCINTOSH	MCINTOSH COAL 230 KV LN	230.00	230.00	Steel Tower	0.00	0.00	1	795 ACSR	
168	MCINTOSH	MCINTOSH CT 230 KV LN	230.00	230.00	Concrete Three-Pole	0.42	0.00	1	1033 ACSR	
169	MCINTOSH	PURRYSBURG (SPSCA) 230 KV (	230.00	230.00	Steel H-Frame	1.98	0.00	1	1272 ACSR	
170	MCINTOSH	WEST MCINTOSH (WHITE) 230 K	230.00	230.00	Concrete Pole	0.40	0.00	1	1351 ACSS	
171	BOWEN	MCCONNENELL ROAD 230KV	230.00	230.00	Steel H-Frame	1.61	0.00	1	795 ACSR	
172	BOWEN	MCCONNENELL ROAD 230KV	230.00	230.00	Steel Tower	8.52	0.00	1	1113 ACSR	
173	MCDONOUGH CC #4 TIE LINE	MCDONOUGH CC #4 TIE LINE	230.00	230.00	Steel Pole	0.83	0.00	1	1113 ACSR	
174	MCDONOUGH CC #5 TIE LINE	MCDONOUGH CC #5 TIE LINE	230.00	230.00	Steel Pole	0.77	0.00	1	795 ACSR	
175	JACK MCDONOUGH	SMYRNA 230 KV	230.00	230.00	Steel Pole	6.93	0.00	1	1351 ACSR	
176	MCDONOUGH CC #6 230 KV TIE LINE	MCDONOUGH CC #6 230 KV TIE LINE	230.00	230.00	Steel Pole	0.34	0.00	1	1351 ACSR	
177	CROSSGATE	DEAN FOREST 230KV	230.00	230.00	Steel Pole	5.50	0.00	1	1351 ACSS	

178	BOULEVARD	DEAN FOREST 230KV	230.00	230.00	Steel Pole	4.00	0.00	1	1351 ACSS	
179	THORNTON RD	TRIBUTARY 230KV	230.00	230.00	Steel Pole	2.80	0.00	1	1351 ACSR	
180	WANSLEY SCRUBBER 230 KV TIE	WANSLEY SCRUBBER 230 KV TIE	230.00	230.00	Concrete Pole	2.00	0.00	1	1351 ACSR	
181	PLANT BOWEN SCRUBBER TIE LINE UNIT 1 & 2	PLANT BOWEN SCRUBBER TIE LINE UNIT 1 & 2	230.00	230.00	Concrete Pole	0.30	0.00	1	795 ACSR	
182	HATCH SAT 1E SERVICE 230KV LINE	HATCH SAT 1E SERVICE 230KV LINE	230.00	230.00	Steel H-Frame	0.23	0.00	1	795 ACSR	
183	HATCH SAT 2E SERVICE 230KV LINE	HATCH SAT 2E SERVICE 230KV LINE	230.00	230.00	Steel Pole	0.19	0.00	1	1351 ACSR	
184	230 KV Underground		230.00		VAR	0.20	0.00			
185	115 KV Underground		115.00		VAR	12.00	0.00			
186	115 KV Overhead Wood Lines		115.00		VAR	4,737.00	33.00			
187	115 KV Overhead Steel Lines		115.00		VAR	1,091.00	81.00			14
188	69 KV Wood Lines		69.00		VAR	112.00	23.00			
189	69 KV Steel Lines		69.00		VAR	3.00	0.00			
190	46 KV Lines		46.00		VAR	2,648.19	6.40			3
36	TOTAL					12,295.29	202.63	175		385,1

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions o
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and I Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other cha

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage K (Operatin
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	BLAKELY PRIMARY	WEBB (APC) 115 KV	0.70	WHP	10.00	1	1	636	ACSR	1/PHASE	1
2	CARTERSVILLE 183592	CARTERSVILLE #7 46 KV	(0.97)	WSP	15.00	1	1	4/0	Copper	1/PHASE	
3	MILLHAVEN ANNEX	RIVER STREET (BLACK) 46 KV	0.05	CSP	15.00	1	1	795	AAC	1/PHASE	
44	TOTAL		(0.22)		40.00	3	3				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional cha be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattende to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capac
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole owner equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other tha of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in re case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Nu Tra
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
1	1 ABBEVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
2	2 ABCD FARMS PM	Distribution	Unattended	46.00	12.00		0.50	2	
3	3 ABCD FARMS PM	Distribution	Unattended	46.00	12.00			1	
4	4 ACORN CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
5	5 ACWORTH	Distribution	Unattended	115.00	12.00		44.80	2	
6	6 ADAIRSVILLE	Distribution	Unattended	115.00	25.00		80.00	2	
7	7 ADAMS PM	Distribution	Unattended	46.00	12.00		0.25	1	
8	8 ADDLESTONE	Distribution	Unattended	46.00	12.00		5.25	1	
9	9 AERO COMMANDER	Distribution	Unattended	12.00	0.48		1.68	1	
10	10 AINSLIE PM	Distribution	Unattended	46.00	12.00		0.25	1	
11	11 AIR PRODUCTS AND CHEMICALS	Distribution	Unattended	115.00	4.00		44.80	2	
12	12 AIRGAS (Pendergrass)	Distribution	Unattended	230.00	4.00		50.00	2	
13	13 AIRGAS (Pendergrass)	Distribution	Unattended	230.00	25.00		40.00	1	
14	14 AIRLINE	Transmission	Unattended	115.00	46.00		50.00	2	
15	15 AIRPORT ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
16	16 ALADDIN FIBER ONE #2 PD	Distribution	Unattended	46.00	4.00		2.50	1	
17	17 ALADDIN FIBER ONE #2 PD	Distribution	Unattended	46.00	4.00		2.50	1	
18	18 ALADDIN MILLS	Distribution	Unattended	46.00	0.48		10.50	2	
19	19 ALADDIN MILLS #2	Distribution	Unattended	46.00	0.48		12.50	2	
20	20 ALADDIN MILLS #3	Distribution	Unattended	46.00	0.48		6.25	1	
21	21 ALADDIN MILLS #3	Distribution	Unattended	46.00	0.48		6.25	1	

22	22 ALADDIN MILLS (Forsyth)	Distribution	Unattended	12.00	0.60		3.50	1	
23	23 ALAPAHA	Distribution	Unattended	115.00	12.00		10.50	1	
24	24 ALCOVY ROAD	Transmission	Unattended	115.00	46.00		56.00	1	
25	25 ALCOVY ROAD	Transmission	Unattended	115.00	25.00		25.00	1	
26	26 ALDORA MILLS #3	Distribution	Unattended	69.00	4.00		25.00	1	
27	27 ALEXANDER DRIVE	Distribution	Unattended	115.00	13.80		80.00	2	
28	28 ALIMENTA	Distribution	Unattended	46.00	0.48		0.75	2	
29	29 ALIMENTA	Distribution	Unattended	46.00	0.48		1.33	4	
30	30 ALKEN-ZEIGLER	Distribution	Unattended	46.00	0.48		0.50	1	
31	31 ALLATOONA HEIGHTS PM	Distribution	Unattended	46.00	12.00		0.28	1	
32	32 ALLEN ROAD	Distribution	Unattended	115.00	12.00		80.00	2	
33	33 ALPHARETTA	Distribution	Unattended	230.00	25.00		60.00	1	
34	34 ALTAMAHA BOULEVARD	Distribution	Unattended	115.00	12.00		25.00	1	
35	35 ALTO	Distribution	Unattended	115.00	12.00		7.00	1	
36	36 ALTO	Distribution	Unattended	115.00	12.00		25.00	1	
37	37 AMERICAN GRANITE QUARRIES	Distribution	Unattended	46.00	12.00		2.50	3	
38	38 AMERICUS	Transmission	Unattended	115.00	12.00		25.00	1	
39	39 AMERICUS	Transmission	Unattended	115.00	46.00		50.00	2	
40	40 AMERICUS	Transmission	Unattended	115.00	12.00		22.40	1	
41	41 AMHERST	Distribution	Unattended	115.00	12.00		44.80	2	
42	42 ANCHOR GLASS	Distribution	Unattended	115.00	12.00		10.50	1	
43	43 ANCHOR GLASS	Distribution	Unattended	115.00	12.00		10.00	1	
44	44 ANDERSONVILLE PD	Distribution	Unattended	46.00	12.00		2.50	1	
45	45 ANGLO AMERICAN CLAY TEMPORARY PM	Distribution	Unattended	46.00	12.00		0.25	1	
46	46 ANGLO AMERICAN CLAY TEMPORARY PM	Distribution	Unattended	46.00	12.00		0.50	2	
47	47 ANTHONY PM	Distribution	Unattended	46.00	12.00		0.25	1	
48	48 ANTHONY PM	Distribution	Unattended	46.00	12.00			2	
49	49 ANTIOCH ROAD	Distribution	Unattended	115.00	46.00		40.00	1	
50	50 ANTIOCH ROAD	Distribution	Unattended	115.00	46.00		60.00	1	
51	51 ANTIOCH ROAD	Distribution	Unattended	46.00	12.00		8.40	2	
52	52 APAC (Camak)	Distribution	Unattended	46.00	25.00		14.00	2	
53	53 APALACHEE AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
54	54 AQUILLA	Distribution	Unattended	115.00	12.00		25.00	1	
55	55 AQUILLA	Distribution	Unattended	115.00	25.00		25.00	1	
56	56 ARAGON	Distribution	Unattended	46.00	12.00		14.00	2	

57	57 ARAGON PRIMARY	Transmission	Unattended	115.00	46.00		50.00	1	
58	58 ARBOR	Distribution	Unattended	115.00	25.00		25.00	1	
59	59 ARCHER DANIELS MIDLAND (Valdosta)	Distribution	Unattended	115.00	12.00		22.40	1	
60	60 ARGOS (Atlanta)	Distribution	Unattended	115.00	4.00		14.00	2	
61	61 ARLINGTON	Distribution	Unattended	46.00	12.00		7.00	1	
62	62 ARMSTRONG GLASS (Jasper)	Distribution	Unattended	46.00	0.48		1.68	3	
63	63 ARMSTRONG WORLD INDUSTRIES	Distribution	Unattended	115.00	4.00		134.40	4	
64	64 ARMUCHEE	Distribution	Unattended	115.00	12.00		10.50	1	
65	65 ARTESIAN STREET	Distribution	Unattended	115.00	12.00		50.00	2	
66	66 ASAMA COLDWATER MANUFACTURING	Distribution	Unattended	115.00	13.80		44.80	2	
67	67 ASAMA COLDWATER MANUFACTURING	Distribution	Unattended	115.00	13.80		10.50	1	
68	68 ASHBURN PRIMARY	Distribution	Unattended	115.00	12.00		50.00	2	
69	69 ASHBURN PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
70	70 ASHFORD	Distribution	Unattended	230.00	20.00		60.00	1	
71	71 ASSOCIATED RUBBER #1	Distribution	Unattended	46.00	0.48		3.00	6	
72	72 ATHENA	Distribution	Unattended	115.00	25.00		100.00	2	
73	73 ATHENS	Transmission	Unattended	115.00	46.00		50.00	1	
74	74 ATHENS OPERATING PM	Distribution	Unattended	46.00	12.00		0.25	1	
75	75 ATHENS OPERATING PM	Distribution	Unattended	46.00	12.00		0.50	2	
76	76 ATHENS PUMPING	Distribution	Unattended	46.00	4.00		7.00	1	
77	77 ATLANTA FULTON COUNTY WATER TREATMENT	Distribution	Unattended	230.00	12.00		67.20	2	
78	78 ATLANTA INCINERATOR	Distribution	Unattended	20.00	0.48		1.68	1	
79	79 ATLANTA WATER STORAGE (Lois Street)	Distribution	Unattended	115.00	4.00		50.00	2	
80	80 ATLANTA WATER TREATMENT (Bolton)	Distribution	Unattended	115.00	4.00		50.00	2	
81	81 ATLANTA WATER TREATMENT (Bolton)	Distribution	Unattended	115.00	4.00		44.80	2	
82	82 ATLANTA WATER WORKS (Adamsville)	Distribution	Unattended	46.00	4.00		1.68	3	
83	83 ATLANTA WATER WORKS (Moores Mill)	Distribution	Unattended	20.00	2.40		2.00	3	
84	84 ATLANTIC DRIVE	Distribution	Unattended	115.00	20.00		60.00	1	
85	85 ATTAPULGUS	Distribution	Unattended	25.00	4.00		7.00	1	
86	86 ATTAPULGUS	Distribution	Unattended	25.00	4.00		7.00	1	
87	87 AUGUSTA AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	

88	88 AUGUSTA AREA #4 PM	Distribution	Unattended	46.00	12.00		0.25	1	
89	89 AUGUSTA CORPORATE PARK	Distribution	Unattended	230.00	25.00		25.00	1	
90	90 AUGUSTA NEWSPRINT	Distribution	Unattended	230.00	13.80		60.00	1	
91	91 AUGUSTA NEWSPRINT	Distribution	Unattended	230.00	13.80		224.00	4	
92	92 AUSTELL	Distribution	Unattended	115.00	46.00		50.00	1	
93	93 AUSTELL	Distribution	Unattended	115.00	12.00		44.80	2	
94	94 AUSTELL	Distribution	Unattended	115.00	25.00		33.33	1	
95	95 AUSTELL BOX BOARD	Distribution	Unattended	46.00	0.60		14.00	2	
96	96 AUSTIN DRIVE	Distribution	Unattended	115.00	12.00		67.20	3	
97	97 AUTREY FURNITURE	Distribution	Unattended	46.00	12.00		0.75	3	
98	98 AVONDALE MILL ROAD	Distribution	Unattended	115.00	12.00		50.00	2	
99	99 AVONLEA	Distribution	Unattended	230.00	25.00		120.00	2	
100	100 BAINBRIDGE	Distribution	Unattended	115.00	12.00		42.00	2	
101	101 BAINBRIDGE	Distribution	Unattended	115.00	12.00		44.80	2	
102	102 BAKER PLACE	Distribution	Unattended	115.00	12.00		40.00	1	
103	103 BAKER PLACE	Distribution	Unattended	115.00	12.00		25.00	1	
104	104 BAKERS FERRY ROAD	Distribution	Unattended	230.00	20.00		120.00	2	
105	105 BALDWIN	Distribution	Unattended	115.00	12.00		10.50	1	
106	106 BALDWIN	Distribution	Unattended	115.00	12.00		25.00	1	
107	107 BANNING LAKE PM	Distribution	Unattended	46.00	12.00		0.25	1	
108	108 BARCO #1 (TALLAPOOSA) PD	Distribution	Unattended	46.00	4.00		2.50	1	
109	109 BARNESVILLE	Distribution	Unattended	115.00	12.00		50.00	2	
110	110 BARNETT ROAD	Distribution	Unattended	115.00	25.00		56.00	1	
111	111 BARTLETTS FERRY	Transmission	Unattended	14.40	0.48		1.12	3	
112	112 BARTLETTS FERRY	Transmission	Unattended	115.00	6.60		30.00	1	
113	113 BARTLETTS FERRY	Transmission	Unattended	115.00			22.40	1	
114	114 BARTLETTS FERRY	Transmission	Unattended	115.00	12.00		130.00	1	
115	115 BARTLETTS FERRY	Transmission	Unattended	115.00	12.00		44.80	2	
116	116 BARTLETTS FERRY	Transmission	Unattended	13.80	0.48		2.24	2	
117	117 BARTON CHAPEL	Distribution	Unattended	230.00	12.00		33.60	1	
118	118 BARTOW	Distribution	Unattended	46.00	12.00		2.50	3	
119	119 BASE MANUFACTURING	Distribution	Unattended	46.00	0.48		1.68	1	
120	120 BASF (Hartwell)	Distribution	Unattended	46.00	12.00		5.25	1	
121	121 BASSETT FURNITURE	Distribution	Unattended	46.00	0.48		3.50	1	
122	122 BATH	Distribution	Unattended	46.00	12.00		14.00	2	
123	123 BATTLECREEK	Distribution	Unattended	115.00	25.00		40.00	1	

124	124 BAXLEY	Distribution	Unattended	115.00	12.00		25.00	1	
125	125 BAXLEY	Distribution	Unattended	115.00	12.00		22.40	1	
126	126 BAXLEY	Distribution	Unattended	115.00	46.00		50.00	2	
127	127 BAYER CROPSCIENCE	Distribution	Unattended	115.00	12.00		7.00	1	
128	128 BEASLEY TIMBER	Distribution	Unattended	46.00	0.48		3.36	2	
129	129 BEASLEY TIMBER #2 PD	Distribution	Unattended	46.00	4.00		2.50	1	
130	130 BEAULIEU AMERICA (Royston)	Distribution	Unattended	46.00	0.60		3.86	2	
131	131 BEAVER DRIVE	Distribution	Unattended	115.00	12.00		40.00	1	
132	132 BEAVER DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
133	133 BEAVERS ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
134	134 BEKAERT STEEL WIRE	Distribution	Unattended	115.00	12.00		44.80	2	
135	135 BELAIR	Distribution	Unattended	115.00	12.00		40.00	1	
136	136 BELL	Distribution	Unattended	115.00	12.00		25.00	1	
137	137 BELLEVUE	Distribution	Unattended	115.00	12.00		33.60	1	
138	138 BELVEDERE	Distribution	Unattended	20.00	12.00		22.40	1	
139	139 BELVEDERE	Distribution	Unattended	115.00	20.00		41.60	1	
140	140 BELVEDERE	Distribution	Unattended	115.00	12.00		22.40	1	
141	141 BEN HILL	Distribution	Unattended	115.00	20.00		50.00	1	
142	142 BENDIX FRICTION MATERIALS	Distribution	Unattended	46.00	0.48		6.25	1	
143	143 BERCKMAN ROAD	Distribution	Unattended	115.00	13.80		40.00	1	
144	144 BERKELEY LAKE	Distribution	Unattended	230.00	25.00		60.00	1	
145	145 BERKELEY LAKE	Distribution	Unattended	230.00	25.00		33.60	1	
146	146 BERKELEY LAKE	Distribution	Unattended	230.00	25.00		50.00	1	
147	147 BETHLEHEM 115/25-KV	Distribution	Unattended	115.00	25.00		25.00	1	
148	148 BEULAH PM	Distribution	Unattended	46.00	12.00		0.25	1	
149	149 BIBB MANUFACTURING (Percale)	Distribution	Unattended	115.00	4.00		14.00	2	
150	150 BICKERSTAFF CLAY PRODUCTS	Distribution	Unattended	20.00	0.60		2.50	3	
151	151 BIG A	Distribution	Unattended	115.00	12.00		10.50	1	
152	152 BIG CREEK SEWAGE TREATMENT	Distribution	Unattended	20.00	12.00		44.80	2	
153	153 BIG POPLAR	Distribution	Unattended	115.00	12.00		25.00	1	
154	154 BIG POPLAR	Distribution	Unattended	25.00	12.00		10.50	1	
155	155 BIG POPLAR SPRINGS ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
156	156 BILL FRANKS PM	Distribution	Unattended	46.00	12.00		0.25	1	
157	157 BIO	Transmission	Unattended	115.00	46.00		25.00	1	
158	158 BLACK BEAR PM	Distribution	Unattended	46.00	12.00		0.25	1	

159	159 BLACK CREEK	Distribution	Unattended	115.00	13.80		14.00	1	
160	160 BLACKSHEAR	Distribution	Unattended	115.00	12.00		21.00	2	
161	161 BLACKWELLS	Distribution	Unattended	115.00	25.00		40.00	1	
162	162 BLAKELY PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
163	163 BLANCHARD INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		40.00	1	
164	164 BLEYLE AMERICA	Distribution	Unattended	25.00	0.48		1.68	1	
165	165 BLOOMFIELD	Distribution	Unattended	115.00	12.00		22.40	1	
166	166 BLOOMFIELD	Distribution	Unattended	115.00	12.00		40.00	1	
167	167 BLOOMINGDALE	Distribution	Unattended	46.00	13.80		14.00	1	
168	168 BLOOMINGDALE	Distribution	Unattended	46.00	13.80		10.50	1	
169	169 BLOSSOM CREEK	Distribution	Unattended	46.00	12.00		10.50	2	
170	170 BLUE CIRCLE AGGREGATES #1 (Lithonia)	Distribution	Unattended	46.00	0.60		2.50	3	
171	171 BLUE RIDGE MOUNTAIN WOODCRAFT	Distribution	Unattended	46.00	0.48		1.68	3	
172	172 BOAT ROCK ROAD	Distribution	Unattended	20.00	12.00		22.40	1	
173	173 BOAT ROCK ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
174	174 BOBBY JONES	Distribution	Unattended	115.00	12.00		25.00	1	
175	175 BOBBY JONES	Distribution	Unattended	115.00	12.00		40.00	1	
176	176 BOGART	Distribution	Unattended	230.00	25.00		25.00	1	
177	177 BOJO	Distribution	Unattended	115.00	25.00		42.00	4	
178	178 BOLIVAR	Distribution	Unattended	115.00	12.00		25.00	1	
179	179 BOLLING ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
180	180 BOLTON	Distribution	Unattended	115.00	46.00		25.00	1	
181	181 BOLTON	Distribution	Unattended	115.00	20.00		46.67	1	
182	182 BOLTON STREET	Distribution	Unattended	115.00	13.80		40.00	1	
183	183 BOLTON STREET	Distribution	Unattended	115.00	13.80		33.60	1	
184	184 BONANZA	Distribution	Unattended	115.00	25.00		40.00	1	
185	185 BONANZA	Distribution	Unattended	115.00	25.00		67.20	2	
186	186 BONE PM	Distribution	Unattended	46.00	12.00		0.25	1	
187	187 BORAL BRICK	Distribution	Unattended	115.00	13.80		10.50	1	
188	188 BOSTON	Distribution	Unattended	69.00	12.00		7.00	1	
189	189 BOULEVARD (Atlanta)	Transmission	Unattended	115.00	20.00		60.00	1	
190	190 BOULEVARD (Atlanta)	Transmission	Unattended	115.00	20.00		112.00	2	
191	191 BOULEVARD (Savannah)	Transmission	Unattended	115.00	13.80		37.21	1	
192	192 BOWDON	Distribution	Unattended	46.00	12.00		14.00	2	

193	193 BOWDON JUNCTION PM	Distribution	Unattended	46.00	12.00		0.25	1	
194	194 BOWEN	Generation	Attended	20.00	13.80		140.00	2	
195	195 BOWEN	Generation	Attended	18.00	4.00		40.00	2	
196	196 BOWEN	Generation	Attended	25.00	4.00		80.00	2	
197	197 BOWEN	Generation	Attended	23.00	4.16		45.00	1	
198	198 BOWEN	Generation	Attended	25.00	0.60	1	9.60	1	
199	199 BOWEN	Generation	Attended	20.00	4.00		44.80	2	
200	200 BOWEN	Generation	Attended	230.00	13.80		115.00	2	
201	201 BOWEN	Generation	Attended	25.00	4.00		67.20	3	
202	202 BOWEN	Generation	Attended	230.00	4.00		25.00	1	
203	203 BOWEN	Generation	Attended	500.00	25.00		900.00	3	
204	204 BOWEN	Generation	Attended	25.00	4.00		20.00	1	
205	205 BOWEN	Generation	Attended	25.00	13.80		140.00	2	
206	206 BOWEN	Generation	Attended	230.00	25.00		900.00	3	
207	207 BOWEN	Generation	Attended	500.00			2052.00	6	
208	208 BOWEN NPDES	Distribution	Attended	46.00	4.00		3.75	1	
209	209 BOWEN PUMPING	Distribution	Attended	115.00	4.00		22.40	4	
210	210 BOWMAN	Distribution	Unattended	46.00	12.00		5.25	1	
211	211 BOXWOOD	Distribution	Unattended	115.00	12.00		22.40	1	
212	212 BOYD PM	Distribution	Unattended	46.00	12.00		0.25	1	
213	213 BRADLEY INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		40.00	1	
214	214 BRADLEY INDUSTRIAL PARK	Distribution	Unattended	115.00	25.00		33.60	1	
215	215 BREMEN-BOWDEN INVESTMENT	Distribution	Unattended	46.00	0.48		3.50	1	
216	216 BRENTWOOD	Distribution	Unattended	115.00	12.00		10.50	1	
217	217 BRIAR VISTA	Distribution	Unattended	115.00	20.00		120.00	2	
218	218 BRIAR VISTA	Distribution	Unattended	20.00	12.00		22.40	1	
219	219 BRIDGEPORT BRASS	Distribution	Unattended	46.00	0.24		5.60	6	
220	220 BROAD RIVER FOREST PM	Distribution	Unattended	46.00	12.00		0.25	1	
221	221 BROAD RIVER STONE	Distribution	Unattended	46.00	25.00		7.00	1	
222	222 BROADWAY	Distribution	Unattended	115.00	12.00		40.00	2	
223	223 BROADWAY	Distribution	Unattended	115.00	12.00		22.40	1	
224	224 BRODIE METER	Distribution	Unattended	46.00	0.48		2.80	1	
225	225 BRONWOOD	Distribution	Unattended	46.00	12.00		5.25	1	
226	226 BROOKHAVEN BOULEVARD	Distribution	Unattended	115.00	12.00		44.80	2	
227	227 BROOKHAVEN BOULEVARD	Distribution	Unattended	115.00	12.00		40.00	2	
228	228 BROOKLET	Distribution	Unattended	115.00	12.00		10.50	1	
229		Distribution	Unattended	115.00	13.80		40.00	1	

	229 BROWN AND WILLIAMSON TOBACCO								
230	230 BROWN BROTHERS #2	Distribution	Unattended	12.00	2.40		2.80	3	
231	231 BROWN BROTHERS SAND PIT	Distribution	Unattended	12.00	2.40		7.00	2	
232	232 BROWN FARM ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
233	233 BROWN FARM ROAD	Distribution	Unattended	25.00	12.00		10.50	1	
234	234 BRUNSWICK	Distribution	Unattended	115.00	12.00		80.00	2	
235	235 BUCKHEAD (Madison) (NEW)	Distribution	Unattended	115.00	25.00		25.00	1	
236	236 BUCKHEAD PRIMARY	Distribution	Unattended	230.00	20.00		60.00	1	
237	237 BUCKHEAD PRIMARY	Distribution	Unattended	230.00	20.00		112.00	2	
238	238 BUDWEISER PM	Distribution	Unattended	46.00	12.00		0.75	3	
239	239 BUENA VISTA	Distribution	Unattended	46.00	12.00		14.00	2	
240	240 BUENA VISTA	Distribution	Unattended	46.00	25.00		10.50	2	
241	241 BUFFALO ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
242	242 BUFFALO ROAD	Distribution	Unattended	25.00	12.00		10.50	1	
243	243 BUFORD	Distribution	Unattended	115.00	12.00		22.40	1	
244	244 BUFORD	Distribution	Unattended	115.00	46.00		25.00	1	
245	245 BUHLER QUALITY YARNS	Distribution	Unattended	115.00	12.00		28.00	4	
246	246 BULK FABRICATED PRODUCTS	Distribution	Unattended	46.00	0.48		1.68	1	
247	247 BULL CREEK	Distribution	Unattended	115.00	12.00		80.00	2	
248	248 BULL MOOSE TUBE	Distribution	Unattended	46.00	0.48		5.60	1	
249	249 BURGESS PIGMENT	Distribution	Unattended	46.00	0.48		2.80	1	
250	250 BURGESS PIGMENT #2 PD	Distribution	Unattended	46.00	12.00		5.00	1	
251	251 BURKHALTER ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
252	252 BURNT HICKORY	Distribution	Unattended	115.00	12.00		50.00	2	
253	253 BURTON	Distribution	Unattended	46.00	12.00		7.00	1	
254	254 BURTON HYDRO	Generation	Attended	46.00	6.60		10.50	1	
255	255 BUTLER	Distribution	Unattended	46.00	12.00		5.25	1	
256	256 BUTLER	Distribution	Unattended	46.00	12.00		9.37	2	
257	257 BUTLER	Distribution	Unattended	230.00	46.00		33.60	1	
258	258 BUTLER	Distribution	Unattended	115.00	46.00		25.00	1	
259	259 BUTLER STREET	Distribution	Unattended	115.00	20.00		180.00	3	
260	260 BUTLER STREET	Distribution	Unattended	115.00	20.00		60.00	1	
261	261 CADWELL PD	Distribution	Unattended	46.00	12.00		2.50	1	
262	262 CAGLES (Perry)	Distribution	Unattended	115.00	12.00		25.00	1	
263	263 CAGLES (Perry)	Distribution	Unattended	115.00	12.00		21.00	2	

264	264 CALHOUN COUNTY PRISON #1 PD (East)	Distribution	Unattended	46.00	12.00		2.50	1	
265	265 CALHOUN COUNTY PRISON #2 PD (West)	Distribution	Unattended	46.00	12.00		2.50	1	
266	266 CALHOUN ROAD	Distribution	Unattended	115.00	12.00		44.80	2	
267	267 CALHOUN ROAD	Distribution	Unattended	115.00	12.00		21.00	2	
268	268 CAMP JOSEY	Transmission	Unattended	230.00	46.00		46.67	1	
269	269 CAMP JOSEY #2 PD	Distribution	Unattended	46.00	12.00		2.50	1	
270	270 CAMP ODOM PM	Distribution	Unattended	46.00	12.00		0.33	1	
271	271 CANDLER AREA PM	Distribution	Unattended	46.00	12.47		0.25	1	
272	272 CANDLER HOSPITAL	Distribution	Unattended	13.20	0.28		4.20	3	
273	273 CANNONGATE ACRES PM	Distribution	Unattended	46.00	12.00		0.25	1	
274	274 CANON	Distribution	Unattended	46.00	12.00		3.75	1	
275	275 CANTON #2	Distribution	Unattended	115.00	25.00		60.00	1	
276	276 CANYON ROAD	Distribution	Unattended	46.00	12.00		4.69	1	
277	277 CARL FINDLEY PM	Distribution	Unattended	46.00	12.00		0.25	1	
278	278 CARLTON RURAL PM	Distribution	Unattended	46.00	12.00		0.25	1	
279	279 CARMEUSE MINE #1 PD	Distribution	Unattended	46.00	0.48		2.00	1	
280	280 CARNESVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
281	281 CARPENTER FLAT	Distribution	Unattended	115.00	25.00		40.00	1	
282	282 CARROLLTON	Transmission	Unattended	115.00	46.00		50.00	1	
283	283 CARROLLTON #2	Distribution	Unattended	115.00	12.00		80.00	2	
284	284 CARWOOD MANUFACTURING	Distribution	Unattended	12.00	0.48		2.10	1	
285	285 CASCADE HEIGHTS	Distribution	Unattended	115.00	20.00		56.00	1	
286	286 CASSVILLE	Distribution	Unattended	46.00	25.00		10.00	1	
287	287 CASTLEBERRY ROAD	Distribution	Unattended	115.00	12.00		33.60	1	
288	288 CASTLEBERRY ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
289	289 CASTLEBERRY ROAD	Distribution	Unattended	25.00	12.00		25.00	1	
290	290 CAVE SPRING #2	Distribution	Unattended	230.00	12.00		25.00	1	
291	291 CDC (Clifton Road)	Distribution	Unattended	20.00	4.00		80.00	4	
292	292 CEDAR CREEK ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
293	293 CEDAR HILL	Distribution	Unattended	230.00	12.00		40.00	1	
294	294 CEDAR SPRINGS	Distribution	Unattended	115.00	12.00		10.50	1	
295	295 CEDAR SPRINGS	Distribution	Unattended	115.00	13.80		80.00	2	
296	296 CEDAR VILLAGE	Distribution	Unattended	230.00	25.00		60.00	1	
297	297 CEDARTOWN	Transmission	Unattended	230.00	46.00		56.00	1	
298	298 CELANESE	Transmission	Unattended	115.00	12.00		33.60	1	
299	299 CENTRAL AVENUE	Distribution	Unattended	115.00	13.80		40.00	1	

300	300 CENTRAL STATE HOSPITAL	Distribution	Unattended	115.00	12.00		25.00	4	
301	301 CERTAINTEED (Athens)	Distribution	Unattended	115.00	25.00		33.60	1	
302	302 CERTAINTEED (Athens)	Distribution	Unattended	115.00	12.00		40.00	1	
303	303 CERTAINTEED (Social Circle)	Distribution	Unattended	46.00	0.48		3.50	1	
304	304 CERTAINTEED (Social Circle)	Distribution	Unattended	46.00	0.48		1.68	1	
305	305 CHADBOURN GOTHAM	Distribution	Unattended	115.00	12.00		40.00	1	
306	306 CHARLES WHITLOCK PM	Distribution	Unattended	46.00	12.00		0.25	1	
307	307 CHATHAM COUNTY INDUSTRIAL	Distribution	Unattended	115.00	25.00		80.00	2	
308	308 CHATSWORTH	Distribution	Unattended	115.00	25.00		67.20	2	
309	309 CHATTAHOOCHEE	Distribution	Unattended	115.00	20.00		56.00	1	
310	310 CHAUNCEY	Distribution	Unattended	115.00	12.00		14.00	2	
311	311 CHEROKEE	Distribution	Unattended	46.00	13.80		14.00	1	
312	312 CHEROKEE BRICK	Distribution	Unattended	12.00	0.60		5.60	2	
313	313 CHEROKEE ROAD	Transmission	Unattended	115.00	46.00		25.00	1	
314	314 CHEROKEE ROAD	Transmission	Unattended	115.00	12.00		25.00	1	
315	315 CHICKAMAUGA	Distribution	Unattended	115.00	25.00		67.20	2	
316	316 CHICKAMAUGA	Distribution	Unattended	115.00	12.00		25.00	1	
317	317 CHICOPEE MANUFACTURING	Distribution	Unattended	115.00	12.00		18.75	2	
318	318 CHICOPEE MANUFACTURING	Distribution	Unattended	115.00	25.00		10.50	1	
319	319 CHICOPEE WOODS PM	Distribution	Unattended	46.00	12.00		0.75	3	
320	320 CHILDRESS PM	Distribution	Unattended	46.00	12.00		0.25	1	
321	321 CHINA HILL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
322	322 CHINA HILL ROAD PM	Distribution	Unattended	46.00	12.00		0.50	2	
323	323 CHINCHILLA ROAD PM	Distribution	Unattended	46.00	12.00		1.00	3	
324	324 CHLORIDE	Distribution	Unattended	115.00	12.00		22.40	1	
325	325 CHOKEE PLANTATION PM	Distribution	Unattended	46.00	12.00		0.25	1	
326	326 CHOKEE PLANTATION PM	Distribution	Unattended	46.00	12.00		0.50	2	
327	327 CHOKEE PLANTATION #2 PM	Distribution	Unattended	46.00	0.48		0.30	1	
328	328 CHULA	Distribution	Unattended	46.00	12.00		5.25	1	
329	329 CITGO	Distribution	Unattended	13.20	2.40		2.50	3	
330	330 CLARKESVILLE	Distribution	Unattended	46.00	12.00		9.37	2	
331	331 CLARKESVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
332	332 CLARKS BRIDGE	Distribution	Unattended	46.00	12.00	7	10.50	1	
333	333 CLARKSTON	Distribution	Unattended	115.00	25.00		60.00	1	
334	334 CLARKSTON	Distribution	Unattended	115.00	12.00		44.80	2	
335	335 CLAXTON	Transmission	Unattended	115.00	12.00		22.40	1	
336	336 CLAYTON	Distribution	Unattended	115.00	12.00		42.00	4	

337	337 CLAYTON MARCUS PM	Distribution	Unattended	46.00	12.00		0.25	1	
338	338 CLEARWATER ROAD PM	Distribution	Unattended	46.00	12.00		0.75	3	
339	339 CLERMONT JUNCTION	Distribution	Unattended	115.00	25.00		44.80	2	
340	340 CLOUDLAND CANYON	Distribution	Unattended	46.00	12.00		0.25	1	
341	341 CLOUDLAND CANYON	Distribution	Unattended	230.00	25.00		25.00	1	
342	342 CLOVERLEAF	Distribution	Unattended	230.00	12.00		33.60	1	
343	343 CLYATTVILLE	Distribution	Unattended	69.00	12.00		5.25	1	
344	344 COATS AMERICAN (Toccoa)	Distribution	Unattended	12.00	4.00		3.50	1	
345	345 COATS AND CLARK (Albany)	Distribution	Unattended	46.00	0.60		7.00	1	
346	346 COBB	Distribution	Unattended	46.00	12.00		7.00	1	
347	347 COBB COUNTY R. L. SUTTON WRF	Distribution	Unattended	115.00	4.00		25.00	1	
348	348 COBB COUNTY R. L. SUTTON WRF	Distribution	Unattended	115.00	4.00		25.00	1	
349	349 COBB MARIETTA WATER #1 (Johnson Ferry)	Distribution	Unattended	20.00	4.00		6.25	1	
350	350 COBB MARIETTA WATER #2 (Johnson Ferry)	Distribution	Unattended	20.00	4.00		6.25	1	
351	351 COBB MARIETTA WATER (Allatoona)	Distribution	Unattended	115.00	4.00		10.50	2	
352	352 COBB MARIETTA WATER (Lower Roswell)	Distribution	Unattended	20.00	4.00		28.00	2	
353	353 COBB MARIETTA WATER (Wyckoff)	Distribution	Unattended	115.00	4.00		10.50	1	
354	354 COBB MARIETTA WATER (Wyckoff)	Distribution	Unattended	115.00	4.00		10.50	1	
355	355 COBB PLACE	Distribution	Unattended	230.00	25.00		56.00	1	
356	356 COBB PLACE	Distribution	Unattended	230.00	12.00		33.60	1	
357	357 COBLE DAIRY PD	Distribution	Unattended	46.00	12.00		2.50	1	
358	358 COCA COLA (Hapeville)	Distribution	Unattended	115.00	20.00		25.00	1	
359	359 COCHRAN PRIMARY	Distribution	Unattended	115.00	12.00		25.00	1	
360	360 COCHRAN PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
361	361 CODY ROAD	Distribution	Unattended	115.00	12.00		67.20	2	
362	362 COLEMAN	Distribution	Unattended	46.00	12.00		4.69	1	
363	363 COLEMAN (Savannah)	Distribution	Unattended	115.00	13.80		22.40	1	
364	364 COLEMAN (Savannah)	Distribution	Unattended	115.00	13.80		25.00	1	
365	365 COLONELS ISLAND	Distribution	Unattended	115.00	25.00		25.00	1	
366	366 COLONELS ISLAND	Distribution	Unattended	115.00	46.00		22.40	1	
367	367 COLONIAL PIPELINE (Armuchee)	Distribution	Unattended	115.00	4.00		7.00	1	
368	368 COLONIAL PIPELINE (Bremen)	Distribution	Unattended	115.00	4.00		18.75	2	
369	369 COLONIAL PIPELINE (Bremen)	Distribution	Unattended	115.00	4.00		44.80	2	

370	370 COLONIAL PIPELINE (Dacula)	Distribution	Unattended	115.00	4.00		21.00	2	
371	371 COLONIAL PIPELINE (Dacula)	Distribution	Unattended	115.00	4.00		44.80	2	
372	372 COLONIAL PIPELINE (Danielsville)	Distribution	Unattended	115.00	4.00		21.00	2	
373	373 COLONIAL PIPELINE (Powder Springs)	Distribution	Unattended	115.00	4.00		28.00	2	
374	374 COLONIAL PIPELINE (Smyrna)	Distribution	Unattended	115.00	4.00		21.00	2	
375	375 COLOR IMAGE	Distribution	Unattended	46.00	0.48		2.10	1	
376	376 COLQUITT	Distribution	Unattended	115.00	12.00		25.00	1	
377	377 COLUMBUS	Distribution	Unattended	115.00	12.00		80.00	2	
378	378 COLUMBUS FOUNDRY	Distribution	Unattended	115.00	12.00		56.00	1	
379	379 COLUMBUS FOUNDRY	Distribution	Unattended	115.00	12.00		22.40	1	
380	380 COLUMBUS SEWAGE	Distribution	Unattended	115.00	12.00		14.00	2	
381	381 COLUMBUS SQUARE	Distribution	Unattended	115.00	12.00		67.20	3	
382	382 COMER PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
383	383 COMER PRIMARY	Distribution	Unattended	115.00	25.00		25.00	1	
384	384 COMMERCE PRIMARY	Distribution	Unattended	115.00	12.00		50.00	2	
385	385 COMMODORE PARK	Distribution	Unattended	115.00	12.00		25.00	1	
386	386 COMOLLI GRANITE	Distribution	Unattended	46.00	0.48		1.12	1	
387	387 CONCORD	Distribution	Unattended	46.00	12.00		3.75	3	
388	388 CONCORD GROVE	Distribution	Unattended	20.00	12.00		25.00	1	
389	389 CONCORD GROVE	Distribution	Unattended	115.00	20.00		80.00	2	
390	390 CONCORD ROAD	Distribution	Unattended	115.00	12.00		50.00	2	
391	391 CONCORD ROAD	Distribution	Unattended	20.00	12.00		22.40	1	
392	392 CONSOLIDATED MINERALS PD	Distribution	Unattended	46.00	12.00		2.50	1	
393	393 CONTAINER CORPORATION OF AMERICA	Distribution	Unattended	25.00	0.48		2.80	1	
394	394 CONYERS	Transmission	Unattended	230.00	46.00		40.00	1	
395	395 CONYERS	Transmission	Unattended	115.00	25.00		44.80	2	
396	396 COOLIDGE	Distribution	Unattended	69.00	12.00		5.25	1	
397	397 COOPER BRIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
398	398 COOPER TIRE	Distribution	Unattended	115.00	13.80		22.40	1	
399	399 COOPER TOOLS	Distribution	Unattended	46.00	0.48		3.50	1	
400	400 COOPER TOOLS	Distribution	Unattended	46.00	0.48		3.50	1	
401	401 COOSA	Distribution	Unattended	115.00	12.00		44.80	2	
402	402 COOSAWATTEE	Transmission	Unattended	115.00	12.00		10.50	1	
403	403 COOSAWATTEE	Transmission	Unattended	115.00	12.00		14.00	2	

404	404 CORINTH ROAD	Distribution	Unattended	115.00	25.00		50.00	1	
405	405 CORNELIA	Distribution	Unattended	115.00	12.00		22.40	1	
406	406 CORNELIA	Distribution	Unattended	115.00	46.00		25.00	1	
407	407 CORNELL AVENUE	Distribution	Unattended	46.00	13.80		14.00	1	
408	408 CORNELL AVENUE	Distribution	Unattended	46.00	13.80		14.00	1	
409	409 CORPORATE RIDGE	Distribution	Unattended	115.00	25.00		67.20	2	
410	410 COTTON PRIMARY	Transmission	Unattended	230.00	46.00		40.00	1	
411	411 COTTON PRIMARY	Transmission	Unattended	230.00	46.00		33.60	1	
412	412 COUNTY FARM ROAD	Distribution	Unattended	115.00	12.00		10.50	1	
413	413 COVINGTON INDUSTRIAL	Transmission	Unattended	115.00	46.00		50.00	1	
414	414 CRAWFISH CREEK	Transmission	Unattended	230.00	46.00		60.00	1	
415	415 CRAWFORD	Distribution	Unattended	46.00	12.00		14.00	2	
416	416 CRAWFORDVILLE	Distribution	Unattended	46.00	8.00		5.25	1	
417	417 CREEK PARK	Distribution	Unattended	230.00	20.00		120.00	2	
418	418 CROOKED RIVER	Distribution	Unattended	115.00	25.00		44.80	2	
419	419 CROOKED RIVER	Distribution	Unattended	115.00	12.00		22.40	1	
420	420 CROSSGATE	Transmission	Unattended	230.00	25.00		50.00	1	
421	421 CROSSROADS PARKWAY	Distribution	Unattended	115.00	25.00		50.00	1	
422	422 CRYSTAL BLUE GRANITE PM	Distribution	Unattended	46.00	25.00		0.84	3	
423	423 CRYSTAL LAKE	Distribution	Unattended	115.00	25.00		60.00	1	
424	424 CRYSTAL LAKE	Distribution	Unattended	25.00	12.00		7.00	1	
425	425 CSX INTERMODAL (Fairburn)	Distribution	Unattended	115.00	12.00		10.50	1	
426	426 CSX TRANSPORTATION PM (Fitzgerald)	Distribution	Unattended	46.00	12.00		0.50	2	
427	427 CSX TRANSPORTATION PM (Fitzgerald)	Distribution	Unattended	46.00	12.00		0.25	1	
428	428 CULVERTON #3 PM	Distribution	Unattended	46.00	12.00		0.50	2	
429	429 CUMBERLAND	Distribution	Unattended	230.00	20.00		60.00	1	
430	430 CUMMING	Distribution	Unattended	115.00	12.00		33.60	1	
431	431 CUMMING	Distribution	Unattended	115.00	12.00		89.60	4	
432	432 CURRAHEE HEIGHTS	Distribution	Unattended	115.00	12.00		25.00	1	
433	433 CUTHBERT	Distribution	Unattended	46.00	12.00		14.00	2	
434	434 CYPRESS POINT	Distribution	Unattended	115.00	13.80		10.50	1	
435	435 DACULA	Distribution	Unattended	115.00	25.00		67.20	2	
436	436 DAHLONEGA PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
437	437 DAHLONEGA PRIMARY	Distribution	Unattended	115.00	12.00		10.50	1	
438	438 DAHLONEGA PRIMARY	Distribution	Unattended	115.00	12.00		25.00	1	

439	439 DALLAS	Distribution	Unattended	46.00	12.00		7.00	1	
440	440 DALTON	Distribution	Unattended	115.00	46.00		50.00	1	
441	441 DALTON	Distribution	Unattended	115.00	12.00		25.00	1	
442	442 DAMES FERRY	Distribution	Unattended	115.00	12.00		7.00	1	
443	443 DARIEN	Distribution	Unattended	115.00	12.00		10.50	1	
444	444 DAVIDSON MINERAL (Lithonia)	Distribution	Unattended	46.00	2.40		6.90	4	
445	445 DAVIE SLICE PM	Distribution	Unattended	46.00	12.00		0.25	1	
446	446 DAVIE SLICE PM	Distribution	Unattended	46.00	12.00		0.25	1	
447	447 DAVIS STREET	Transmission	Unattended	115.00	20.00		40.00	1	
448	448 DAVIS STREET	Transmission	Unattended	115.00	20.00		240.00	4	
449	449 DAVISBORO PD	Distribution	Unattended	46.00	12.00		5.00	1	
450	450 DAWSON	Distribution	Unattended	46.00	25.00		5.25	1	
451	451 DAWSON	Distribution	Unattended	46.00	12.00		10.50	2	
452	452 DAWSON FOREST	Distribution	Unattended	115.00	12.00		21.00	2	
453	453 DAWSON INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		22.40	1	
454	454 DAWSON PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
455	455 DAWSON PRIMARY	Transmission	Unattended	115.00	46.00		22.40	1	
456	456 DEAL BRANCH	Transmission	Unattended	115.00	46.00		25.00	1	
457	457 DEAN FOREST	Transmission	Unattended	115.00	13.80		33.60	1	
458	458 DEAN STEEL BUILDINGS	Distribution	Unattended	46.00	0.48		1.12	1	
459	459 DEARING	Distribution	Unattended	46.00	25.00		7.00	1	
460	460 DECATUR	Distribution	Unattended	115.00	20.00		46.67	1	
461	461 DECATUR	Distribution	Unattended	115.00	20.00		60.00	1	
462	462 DECATUR COUNTY INDUSTRIAL	Distribution	Unattended	115.00	12.00		33.60	1	
463	463 DECATUR COUNTY INDUSTRIAL	Distribution	Unattended	115.00	12.00		33.60	1	
464	464 DEKALB COUNTY SCOTT CANDLER WFP	Distribution	Unattended	115.00	4.00		50.00	2	
465	465 DEKALB COUNTY SEWAGE (Snapfinger Rd)	Distribution	Unattended	20.00	12.00		25.00	1	
466	466 DEKALB COUNTY SEWAGE (Snapfinger Rd)	Distribution	Unattended	25.00	12.00		25.00	1	
467	467 DEKALB COUNTY WATER (Holcombe Bridge)	Distribution	Unattended	25.00	4.00		30.00	2	
468	468 DEKALB VOCATIONAL SCHOOL	Distribution	Unattended	12.00	0.48		1.12	1	
469	469 DELTA AIRLINES #1	Distribution	Unattended	115.00	12.00		40.00	1	
470	470 DELTA AIRLINES #1	Distribution	Unattended	115.00	12.00		40.00	1	
471	471 DELTA AIRLINES #2	Distribution	Unattended	20.00	12.00		25.00	1	

472	472 DELTA AIRLINES #2	Distribution	Unattended	20.00	4.00		2.50	1	
473	473 DEMOREST	Distribution	Unattended	46.00	12.00	7	10.50	1	
474	474 DEMOREST	Distribution	Unattended	46.00	12.00		14.00	2	
475	475 DENNIS STATION ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
476	476 DEPTFORD	Transmission	Unattended	46.00	13.80		44.80	2	
477	477 DERING CIRCLE 115	Distribution	Unattended	115.00	12.00		22.40	1	
478	478 DERING CIRCLE 230	Distribution	Unattended	230.00	20.00		60.00	1	
479	479 DEVEREUX	Distribution	Unattended	46.00	12.00		1.92	2	
480	480 DEVEREUX	Distribution	Unattended	46.00	12.00		0.83	1	
481	481 DEXTER	Distribution	Unattended	46.00	12.00		6.25	1	
482	482 DIAMOND HILL AREA PM	Distribution	Unattended	46.00	12.00		0.25	1	
483	483 DIAMOND HILL AREA PM	Distribution	Unattended	46.00	12.00			1	
484	484 DILLARD PRIMARY	Distribution	Unattended	115.00	25.00		44.80	2	
485	485 DILLARD PRIMARY	Distribution	Unattended	115.00	25.00		25.00	1	
486	486 DITTLER BROTHERS	Distribution	Unattended	20.00	0.48		4.20	1	
487	487 DIVIDEND ROAD	Distribution	Unattended	115.00	12.00		44.80	2	
488	488 DIXIE PECAN PM	Distribution	Unattended	46.00	0.48		0.05	1	
489	489 DIXIE PECAN PM	Distribution	Unattended	46.00			0.05	1	
490	490 DIXIE PIPELINE (Appling)	Distribution	Unattended	12.00	2.40		7.00	2	
491	491 DIXIE PIPELINE (Eatonton)	Distribution	Unattended	46.00	2.40		3.00	3	
492	492 DIXIE PIPELINE (Lumpkin)	Distribution	Unattended	46.00	2.40		3.45	2	
493	493 DIXIE PIPELINE (Milner)	Distribution	Unattended	69.00	2.40		2.50	1	
494	494 DIXIE PIPELINE (Norwood)	Distribution	Unattended	46.00	2.40		14.00	2	
495	495 DIXIE PIPELINE (Putney)	Distribution	Unattended	12.00	4.00		7.00	2	
496	496 DIXIE PIPELINE (Shiloh)	Distribution	Unattended	115.00	2.40		16.80	2	
497	497 DIXIE ROAD	Distribution	Unattended	69.00	12.00		10.50	1	
498	498 DIXON LAKE PM	Distribution	Unattended	46.00	12.00		0.25	1	
499	499 DODD ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
500	500 DODGE AGRICULTURAL PARK PM	Distribution	Unattended	46.00	12.00		0.25	1	
501	501 DODGE EASTMAN INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		25.00	1	
502	502 DOLCO PACKAGING	Distribution	Unattended	46.00	0.48		3.50	1	
503	503 DONALSONVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
504	504 DONNA WAY PM	Distribution	Unattended	46.00	12.00		0.75	3	
505	505 DORAVILLE	Distribution	Unattended	115.00	12.00		40.00	1	
506	506 DORAVILLE	Distribution	Unattended	115.00	46.00		25.00	1	
507	507 DORSEY TRAILERS #2 PM	Distribution	Unattended	12.00	0.48		0.25	3	

508	508 DOSTER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
509	509 DOSTER ROAD #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
510	510 DOUBLE BRIDGES ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
511	511 DOUBLE CHURCHES ROAD	Distribution	Unattended	115.00	25.00		33.33	1	
512	512 DOUBLEGATE	Distribution	Unattended	115.00	12.00		67.20	2	
513	513 DRURY PM	Distribution	Unattended	46.00	12.00		0.50	2	
514	514 DRURY PM	Distribution	Unattended	46.00	12.00		0.25	1	
515	515 DSM CHEMICALS	Distribution	Unattended	115.00	4.00		44.80	2	
516	516 DSM CHEMICALS	Distribution	Unattended	115.00	4.00		134.40	4	
517	517 DSM EVERGREEN	Distribution	Unattended	115.00	13.80		25.00	1	
518	518 DUBLIN	Distribution	Unattended	115.00	46.00		50.00	1	
519	519 DUBLIN	Distribution	Unattended	115.00	12.00		44.80	2	
520	520 DULUTH	Distribution	Unattended	115.00	25.00		56.00	1	
521	521 DUM JON	Transmission	Unattended	115.00	46.00		25.00	1	
522	522 DUNCAN BRIDGE ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
523	523 DUNCAN MILL ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
524	524 DUNCAN MILL ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
525	525 DURHAM PARK	Distribution	Unattended	230.00	25.00		67.20	2	
526	526 DUTCHTOWN ROAD	Distribution	Unattended	115.00	13.80		80.00	2	
527	527 EAGLE GRANITE	Distribution	Unattended	46.00	2.40		0.75	3	
528	528 EAST 12TH STREET	Distribution	Unattended	46.00	12.00		10.50	2	
529	529 EAST AMERICUS	Distribution	Unattended	115.00	12.00		44.80	2	
530	530 EAST ATHENS	Distribution	Unattended	115.00	12.00		160.00	4	
531	531 EAST AUGUSTA	Distribution	Unattended	115.00	13.80		22.40	1	
532	532 EAST BAINBRIDGE	Distribution	Unattended	115.00	25.00		10.50	1	
533	533 EAST BAINBRIDGE	Distribution	Unattended	115.00	12.00		25.00	1	
534	534 EAST BEACH	Distribution	Unattended	115.00	12.00		25.00	1	
535	535 EAST CUTHBERT	Distribution	Unattended	46.00	12.00		9.37	2	
536	536 EAST DAWSON	Distribution	Unattended	46.00	12.00		14.00	2	
537	537 EAST EVANS	Distribution	Unattended	115.00	12.00		22.40	1	
538	538 EAST EVANS	Distribution	Unattended	115.00	12.00		25.00	1	
539	539 EAST EVANS	Distribution	Unattended	115.00	12.00		33.60	1	
540	540 EAST LUMPKIN	Distribution	Unattended	46.00	12.00		14.00	2	
541	541 EAST MACON	Distribution	Unattended	115.00	12.00		22.40	1	
542	542 EAST MAYSVILLE	Distribution	Unattended	115.00	25.00		50.00	2	
543	543 EAST POINT	Distribution	Unattended	115.00	12.00		25.00	1	

544	544 EAST POINT	Distribution	Unattended	115.00	20.00		50.00	1	
545	545 EAST VALDOSTA	Distribution	Unattended	115.00	12.00		22.40	1	
546	546 EAST VALDOSTA	Distribution	Unattended	115.00	12.00		40.00	1	
547	547 EAST VIDALIA	Distribution	Unattended	115.00	12.00		44.80	2	
548	548 EAST VIDALIA	Distribution	Unattended	115.00	12.00		25.00	1	
549	549 EAST VIENNA	Distribution	Unattended	46.00	12.00		14.00	2	
550	550 EASTANOLLEE	Distribution	Unattended	115.00	12.00		25.00	1	
551	551 EASTANOLLEE	Distribution	Unattended	115.00	12.00		10.50	1	
552	552 EASTMAN	Distribution	Unattended	115.00	12.00		22.40	1	
553	553 EATONTON	Distribution	Unattended	46.00	12.00		10.50	2	
554	554 EATONTON	Distribution	Unattended	46.00	12.00		5.25	1	
555	555 EATONTON PRIMARY	Transmission	Unattended	230.00	46.00		22.40	1	
556	556 EATONTON PRIMARY	Transmission	Unattended	230.00	46.00		33.60	1	
557	557 EATONTON PUMPING PM	Distribution	Unattended	46.00	12.00		0.28	1	
558	558 EATONTON PUMPING PM	Distribution	Unattended	46.00	12.00		0.50	2	
559	559 EATONTON RADIO STATION PM	Distribution	Unattended	46.00	12.00		0.25	1	
560	560 ECHECONNEE	Distribution	Unattended	115.00	12.00		33.60	1	
561	561 EDISON	Distribution	Unattended	46.00	12.00		7.00	1	
562	562 ELANCO	Distribution	Unattended	115.00	4.00		22.40	1	
563	563 ELBERTON PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
564	564 ELLAVILLE	Distribution	Unattended	230.00	12.00		7.50	1	
565	565 ELLENWOOD	Distribution	Unattended	115.00	25.00		60.00	1	
566	566 ELLERSLIE	Distribution	Unattended	230.00	25.00		40.00	1	
567	567 ELLIJAY #2	Distribution	Unattended	46.00	12.00		10.50	2	
568	568 ELLIJAY LUMBER	Distribution	Unattended	46.00	0.48		0.75	3	
569	569 ELLIJAY PRIMARY	Transmission	Unattended	230.00	46.00		60.00	1	
570	570 ELLIJAY PRIMARY	Transmission	Unattended	230.00	25.00		40.00	1	
571	571 ELLIJAY PRIMARY	Transmission	Unattended	230.00	12.00		80.00	2	
572	572 EMORY	Distribution	Unattended	115.00	20.00		60.00	1	
573	573 EMORY	Distribution	Unattended	115.00	20.00		56.00	1	
574	574 ENCORE RECYCLING	Distribution	Unattended	115.00	4.00		10.50	1	
575	575 ENGELHARD (Gordon)	Distribution	Unattended	115.00	12.00		33.60	1	
576	576 ENGELHARD (McIntyre)	Distribution	Unattended	115.00	12.00		112.00	2	
577	577 ENGELHARD (Savannah)	Distribution	Unattended	46.00	4.00		16.80	2	
578	578 ENGINEERED FABRICS	Distribution	Unattended	46.00	2.40		7.50	3	
579	579 ENGLISHVILLE	Distribution	Unattended	46.00	25.00		10.50	1	

580	580 ERCO WORLDWIDE	Distribution	Unattended	230.00	25.00		60.00	1	
581	581 ERCO WORLDWIDE	Distribution	Unattended	230.00	25.00		60.00	1	
582	582 ERCO WORLDWIDE	Distribution	Unattended	230.00	25.00		33.60	1	
583	583 ERICK CHURCH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
584	584 ETHICON	Distribution	Unattended	46.00	0.48		6.25	1	
585	585 ETON	Distribution	Unattended	115.00	25.00		21.00	2	
586	586 EUCHEE CREEK	Distribution	Unattended	115.00	12.00		42.54	1	
587	587 EUHARLEE	Distribution	Unattended	115.00	12.00		25.00	1	
588	588 EUREKA	Distribution	Unattended	115.00	25.00		40.00	1	
589	589 EVANS PM	Distribution	Unattended	46.00	12.00		0.25	1	
590	590 EVANS CLAY	Distribution	Unattended	12.00	2.40		2.80	3	
591	591 EVANS PRIMARY	Transmission	Unattended	115.00	12.00		44.80	2	
592	592 EVANS PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
593	593 EVERGREEN	Distribution	Unattended	115.00	25.00		10.50	1	
594	594 FACTORY SHOALS ROAD	Distribution	Unattended	115.00	25.00		33.60	1	
595	595 FACTORY SHOALS ROAD	Distribution	Unattended	115.00	25.00		60.00	1	
596	596 FACTORY SHOALS ROAD	Distribution	Unattended	115.00	25.00		56.00	1	
597	597 FAIR ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
598	598 FAIR ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
599	599 FAIRINGTON RIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
600	600 FAYETTEVILLE	Distribution	Unattended	115.00	12.00		67.20	3	
601	601 FAYETTEVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
602	602 FAYETTEVILLE ROAD	Distribution	Unattended	115.00	20.00		40.00	1	
603	603 FAYETTEVILLE ROAD	Distribution	Unattended	20.00	12.00		22.40	1	
604	604 FAYETTEVILLE ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
605	605 FEDERAL MOGUL	Distribution	Unattended	46.00	12.00		4.69	1	
606	606 FEDERAL PENITENTIARY	Distribution	Unattended	20.00	4.00		12.00	3	
607	607 FENWICK STREET	Distribution	Unattended	115.00	13.80		75.00	3	
608	608 FERGUSON AVENUE	Transmission	Unattended	115.00	13.80		40.00	1	
609	609 FIELDALE (Cornelia)	Distribution	Unattended	115.00	12.00		50.00	2	
610	610 FIELDALE FARMS #1 (Murrayville)	Distribution	Unattended	25.00	0.48		7.00	2	
611	611 FIELDALE FARMS #2 (Murrayville)	Distribution	Unattended	25.00	0.48		7.00	2	
612	612 FIELDALE FARMS (Cornelia)	Distribution	Unattended	12.00	0.48		6.25	1	
613	613 FIELDALE FARMS (Cornelia)	Distribution	Unattended	12.00	0.48		7.00	2	
614	614 FIFE	Distribution	Unattended	115.00	25.00		80.00	2	
615	615 FIFTEENTH STREET	Transmission	Unattended	115.00	13.80		80.00	2	

616	616 FIFTEENTH STREET	Transmission	Unattended	115.00	13.80		40.00	1	
617	617 FIFTEENTH STREET	Transmission	Unattended	115.00	13.80		67.20	2	
618	618 FIFTY SECOND STREET	Distribution	Unattended	115.00	13.80		80.00	2	
619	619 FIRST AVENUE	Transmission	Unattended	115.00	12.00		50.00	2	
620	620 FIRST UNITED ETHANOL	Distribution	Unattended	46.00	25.00		21.00	2	
621	621 FISHING CREEK	Distribution	Unattended	115.00	12.00		22.40	1	
622	622 FITZGERALD	Transmission	Unattended	115.00	46.00		25.00	1	
623	623 FLAT CREEK	Distribution	Unattended	115.00	12.00		33.60	1	
624	624 FLAT CREEK SEWAGE TREATMENT	Distribution	Unattended	46.00	12.00		7.00	1	
625	625 FLAT ROCK ROAD	Distribution	Unattended	115.00	25.00		33.60	1	
626	626 FLAT SHOALS ROAD	Distribution	Unattended	230.00	25.00		56.00	1	
627	627 FLAV-O-RICH IRVINDALE DAIRY	Distribution	Unattended	20.00	0.48		3.50	1	
628	628 FLEMING	Distribution	Unattended	115.00	25.00		10.50	1	
629	629 FLINT RIVER HYDRO	Generation	Attended	46.00	2.40		8.00	1	
630	630 FLINT RIVER PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
631	631 FLINT RIVER PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
632	632 FLIPPEN	Distribution	Unattended	115.00	25.00		50.00	1	
633	633 FLORIDA ROCK (Griffin)	Distribution	Unattended	46.00	4.00		2.50	1	
634	634 FLOWERY BRANCH	Distribution	Unattended	115.00	12.00		22.40	1	
635	635 FLOWERY BRANCH	Distribution	Unattended	115.00	25.00		25.00	1	
636	636 FOLKSTON	Distribution	Unattended	115.00	20.00		25.00	1	
637	637 FOLKSTON	Distribution	Unattended	25.00	20.00		22.40	1	
638	638 FOLKSTON	Distribution	Unattended	115.00	25.00		22.40	1	
639	639 FOREST PARK	Distribution	Unattended	115.00	25.00		44.80	2	
640	640 FOREST PARK	Distribution	Unattended	115.00	25.00		56.00	1	
641	641 FORREST LAKE	Distribution	Unattended	230.00	12.00		50.00	2	
642	642 FORREST LAKE	Distribution	Unattended	230.00	25.00		25.00	1	
643	643 FORREST ROAD (Columbus)	Distribution	Unattended	115.00	25.00		33.60	1	
644	644 FORREST ROAD (Columbus)	Distribution	Unattended	115.00	12.00		40.00	1	
645	645 FORREST ROAD (Macon)	Distribution	Unattended	115.00	25.00		25.00	1	
646	646 FORREST ROAD (Macon)	Distribution	Unattended	115.00	12.00		41.70	1	
647	647 FORSTMANN (Louisville)	Distribution	Unattended	115.00	12.00		9.38	1	
648	648 FORT BENNING	Transmission	Unattended	115.00	46.00		22.40	1	
649	649 FORT BENNING	Transmission	Unattended	115.00	46.00		56.00	1	

650	650 FORT BENNING #2	Transmission	Unattended	46.00	13.80		40.00	1	
651	651 FORT BENNING #2	Transmission	Unattended	115.00	46.00		60.00	1	
652	652 FORT GAINES	Distribution	Unattended	115.00	12.00		10.50	1	
653	653 FORT GILLEM	Distribution	Unattended	115.00	25.00		25.00	1	
654	654 FORT GILLEM	Distribution	Unattended	115.00	12.00	14	22.40	1	
655	655 FORT GORDON	Distribution	Unattended	115.00	12.00		80.00	2	
656	656 FORT GORDON #2	Distribution	Unattended	115.00	12.00		80.00	2	
657	657 FORT GORDON HOSPITAL	Distribution	Unattended	115.00	12.00		25.00	1	
658	658 FORT GORDON SOLAR	Generation	Attended	115.00	34.50		40.00	1	
659	659 FORT MCPHERSON	Distribution	Unattended	20.00	12.00		14.00	2	
660	660 FORT STEWART	Distribution	Unattended	115.00	25.00		100.00	2	
661	661 FORT STEWART SOLAR	Generation	Attended	115.00	34.50		50.00	1	
662	662 FORTY FIFTH STREET	Distribution	Unattended	115.00	12.00		22.40	1	
663	663 FORTY FIFTH STREET	Distribution	Unattended	115.00	12.00		25.00	1	
664	664 FOWLER STREET	Distribution	Unattended	115.00	20.00		60.00	1	
665	665 FOWLER STREET	Distribution	Unattended	115.00	20.00		112.00	2	
666	666 FOX TRACE PM	Distribution	Unattended	46.00	12.00		0.25	1	
667	667 FRANKLIN	Distribution	Unattended	115.00	12.00		22.40	1	
668	668 FRANKLIN	Distribution	Unattended	25.00	12.00		5.00	2	
669	669 FRANKLIN ALUMINUM	Distribution	Unattended	12.00	0.48		3.50	1	
670	670 FREDERICA	Distribution	Unattended	115.00	25.00		44.80	2	
671	671 FRITO-LAY (Kathleen)	Distribution	Unattended	115.00	25.00		25.00	1	
672	672 FRUIT OF THE LOOM (Dillard)	Distribution	Unattended	25.00	4.00		7.00	1	
673	673 FULGHUM FIBRES PD (Dewy Rose)	Distribution	Unattended	46.00	12.00		2.50	1	
674	674 FULGHUM FIBRES (Oliver)	Distribution	Unattended	46.00	4.00		4.69	1	
675	675 FURNACE ROAD	Distribution	Unattended	115.00	12.00		50.00	2	
676	676 FURYS FERRY	Distribution	Unattended	115.00	12.00		25.00	1	
677	677 FURYS FERRY	Distribution	Unattended	115.00	12.00		33.60	1	
678	678 GA ARMY NATIONAL GUARD	Distribution	Unattended	46.00	12.00		7.00	1	
679	679 GAILLARD PRIMARY	Transmission	Unattended	230.00	46.00		80.00	2	
680	680 GAINER COTTON GIN	Distribution	Unattended	46.00	12.00		5.25	1	
681	681 GAINESVILLE #1	Transmission	Unattended	115.00	46.00		50.00	1	
682	682 GAINESVILLE #2	Distribution	Unattended	115.00	25.00		55.74	2	
683	683 GAINESVILLE #2	Distribution	Unattended	115.00	25.00		25.00	1	
684	684 GAINESVILLE #2	Distribution	Unattended	115.00	46.00		50.00	1	
685	685 GAINESVILLE WATER WORKS	Distribution	Unattended	46.00	4.00		14.00	2	

686	686 GAINESVILLE WATER WORKS #2	Distribution	Unattended	46.00	2.40		3.00	2	
687	687 GALLAGER PM	Distribution	Unattended	46.00	12.00		0.25	1	
688	688 GARDEN CITY	Distribution	Unattended	115.00	13.80		50.00	2	
689	689 GARNETT RIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
690	690 GEO SPECIALTY CHEMICAL (HENKEL)	Distribution	Unattended	46.00	0.60		3.50	1	
691	691 GEORGE ANDREWS LOCK & DAM PM	Distribution	Unattended	46.00	12.00		0.50	2	
692	692 GEORGETOWN	Distribution	Unattended	46.00	12.00		4.69	1	
693	693 GEORGETOWN (Savannah)	Distribution	Unattended	115.00	13.80		33.60	1	
694	694 GEORGIA BAPTIST VILLAGE	Distribution	Unattended	12.00	4.00		3.13	1	
695	695 GEORGIA BIOMASS	Distribution	Unattended	115.00	25.00		40.00	1	
696	696 GEORGIA BOARD OF CORRECTIONS	Distribution	Unattended	115.00	12.00		9.38	1	
697	697 GEORGIA IRON WORKS	Distribution	Unattended	115.00	12.00		25.00	1	
698	698 GEORGIA MARBLE #2 (Whitestone)	Distribution	Unattended	46.00	0.48		1.68	1	
699	699 GEORGIA MARBLE #4 (Talking Rock)	Distribution	Unattended	46.00	4.00		4.69	1	
700	700 GEORGIA MARBLE #5 (Marble Hill)	Distribution	Unattended	46.00	2.40		7.50	2	
701	701 GEORGIA MARBLE (Marble Hill)	Distribution	Unattended	46.00	2.40		9.37	2	
702	702 GEORGIA MARBLE (Tate)	Distribution	Unattended	46.00	2.40		2.50	3	
703	703 GEORGIA MARBLE (Tate)	Distribution	Unattended	46.00	12.00		2.50	1	
704	704 GEORGIA PACIFIC (Brunswick)	Distribution	Unattended	115.00	13.80		120.00	2	
705	705 GEORGIA PACIFIC (Durand)	Distribution	Unattended	115.00	12.00		9.38	1	
706	706 GEORGIA PACIFIC (Ellabell)	Distribution	Unattended	115.00	13.80		10.50	1	
707	707 GEORGIA PACIFIC (Monticello)	Distribution	Unattended	69.00	12.00		22.40	1	
708	708 GEORGIA PACIFIC (Sterling)	Distribution	Unattended	115.00	12.00		7.00	1	
709	709 GEORGIA PACIFIC (Vienna)	Distribution	Unattended	115.00	12.00		25.00	1	
710	710 GEORGIA PACIFIC (Warrenton)	Distribution	Unattended	46.00	12.00		7.00	1	
711	711 GEORGIA PACIFIC GYPSUM (Savannah)	Distribution	Unattended	46.00	13.80		25.00	1	
712	712 GEORGIA PACIFIC SAWMILL (Albany)	Distribution	Unattended	115.00	12.00		10.50	1	
713	713 GEORGIA PORTS AUTHORITY	Distribution	Unattended	46.00	13.80		25.00	1	
714	714 GEORGIA PORTS AUTHORITY	Distribution	Unattended	46.00	13.80		25.00	1	
715	715 GEORGIA SQUARE	Distribution	Unattended	115.00	25.00		33.30	1	
716	716 GEORGIA STATE PATROL - FAA BEACON PM	Distribution	Unattended	46.00	12.00		2.50	1	
717	717 GEORGIA SYNTHETICS	Distribution	Unattended	46.00	0.48		3.50	1	
718	718 GEORGIA TECH	Distribution	Unattended	230.00	20.00		120.00	2	

719	719 GEORGIA TECH RESEARCH (Cobb)	Distribution	Unattended	46.00	4.00		4.69	1	
720	720 GEORGIA TUBING	Distribution	Unattended	12.00	0.48		5.60	2	
721	721 GERDAU	Distribution	Unattended	230.00	13.80		60.00	1	
722	722 GERDAU	Distribution	Unattended	34.50	13.80		22.40	1	
723	723 GERDAU	Distribution	Unattended	230.00	34.50	14	72.80	1	
724	724 GERDAU	Distribution	Unattended	230.00	34.50		72.80	1	
725	725 GIBSON	Distribution	Unattended	46.00	12.00		14.00	2	
726	726 GIBSON	Distribution	Unattended	46.00	12.00		7.00	1	
727	727 GILMAN PAPER (Fitzgerald)	Distribution	Unattended	115.00	12.00		11.20	2	
728	728 GLENNVILLE	Distribution	Unattended	115.00	12.00		10.50	1	
729	729 GLYNDALE ROAD	Distribution	Unattended	115.00	12.00		44.80	2	
730	730 GOAT ROCK #2	Distribution	Unattended	115.00	25.00		14.00	2	
731	731 GOAT ROCK HYDRO	Generation	Attended	115.00	12.00		35.00	1	
732	732 GOAT ROCK HYDRO	Generation	Attended	12.00	0.48		0.75	1	
733	733 GOAT ROCK HYDRO	Generation	Attended	115.00	4.00		12.50	1	
734	734 GODFREY ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
735	735 GODLEY TRACT	Distribution	Unattended	115.00	13.80		33.60	1	
736	736 GOLD MINE	Distribution	Unattended	115.00	12.00		44.80	2	
737	737 GOLDEN PEANUT (Dawson)	Distribution	Unattended	46.00	12.00		7.00	1	
738	738 GOODSON ROAD #2 PM	Distribution	Unattended	46.00	12.00		0.75	3	
739	739 GOODYEAR TIRE (Social Circle)	Distribution	Unattended	46.00	2.40		4.69	1	
740	740 GOODYEAR TIRE (Social Circle)	Distribution	Unattended	46.00	0.48		2.10	1	
741	741 GOODYEAR TIRE (Social Circle)	Distribution	Unattended	46.00	0.48		1.68	1	
742	742 GORDON	Transmission	Unattended	115.00	12.00		25.00	1	
743	743 GORDON	Transmission	Unattended	115.00	12.00		10.50	1	
744	744 GORDON ROAD	Distribution	Unattended	115.00	25.00		80.00	2	
745	745 GOSHEN (Savannah)	Distribution	Unattended	115.00	13.80		22.40	1	
746	746 GOSHEN (Savannah)	Distribution	Unattended	115.00	25.00		50.00	1	
747	747 GOSSEN	Distribution	Unattended	46.00	0.48		2.80	1	
748	748 GOUGH CITY	Distribution	Unattended	46.00	12.00		5.25	1	
749	749 GRABALL	Distribution	Unattended	115.00	12.00		7.00	1	
750	750 GRADY	Distribution	Unattended	115.00	20.00		80.00	2	
751	751 GRADY	Distribution	Unattended	115.00	20.00		60.00	1	
752	752 GRADY FLOYD PM	Distribution	Unattended	46.00	12.00		0.25	1	

753	753 GRAHAM PACKAGING #5 PD	Distribution	Unattended	46.00	0.48		3.75	1	
754	754 GRANITEVILLE (Sibley)	Distribution	Unattended	13.80	0.60		8.40	2	
755	755 GRAPHIC PACKAGING	Distribution	Unattended	115.00	13.80		80.00	2	
756	756 GRAPHIC PACKAGING (Augusta)	Distribution	Unattended	115.00	13.80		67.20	2	
757	757 GRAVITT	Distribution	Unattended	115.00	25.00		40.00	1	
758	758 GRAY	Distribution	Unattended	115.00	12.00		42.00	2	
759	759 GREAT DANE	Distribution	Unattended	13.80	0.48		3.00	6	
760	760 GREAT SOUTHWEST AMUSEMENT PARK	Distribution	Unattended	46.00	12.00		5.25	1	
761	761 GREAT SOUTHWEST AMUSEMENT PARK	Distribution	Unattended	46.00	12.00		6.25	1	
762	762 GREEN ACRES	Distribution	Unattended	115.00	25.00		22.40	1	
763	763 GREENBRIAR	Distribution	Unattended	115.00	12.00		25.00	1	
764	764 GREENBRIAR	Distribution	Unattended	115.00	12.00		21.00	2	
765	765 GREENS MILL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
766	766 GREENSBORO	Distribution	Unattended	115.00	12.00		21.00	2	
767	767 GREENVILLE	Distribution	Unattended	46.00	12.00		7.00	1	
768	768 GREENVILLE PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
769	769 GREENWOOD PARK	Distribution	Unattended	115.00	25.00		60.00	1	
770	770 GREENWOOD PARK	Distribution	Unattended	115.00	25.00		62.72	1	
771	771 GRESHAMVILLE PM	Distribution	Unattended	46.00	12.00		0.50	2	
772	772 GREYSTONE PM	Distribution	Unattended	46.00	12.00		0.25	1	
773	773 GREYSTONE GOLF #2 PM	Distribution	Unattended	46.00	12.00		0.33	1	
774	774 GRIFFIN ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
775	775 GRIFFIN ROAD	Distribution	Unattended	115.00	12.00		10.50	1	
776	776 GROVE POINT ROAD	Distribution	Unattended	115.00	13.80		25.00	1	
777	777 GROVE POINT ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
778	778 GROVETOWN PRIMARY	Transmission	Unattended	115.00	12.00		40.00	1	
779	779 GUARDIAN AUTOMOTIVE #1	Distribution	Unattended	46.00	0.48		3.50	1	
780	780 GULFSTREAM #1	Distribution	Unattended	46.00	4.00		9.38	1	
781	781 GULFSTREAM #2	Distribution	Unattended	46.00	4.00		8.40	1	
782	782 GULFSTREAM #3	Distribution	Unattended	46.00	25.00		10.00	1	
783	783 GULFSTREAM HANGAR	Distribution	Unattended	46.00	4.00		7.00	1	
784	784 GUM CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
785	785 GUTHRIE PM	Distribution	Unattended	46.00	12.00		0.25	1	
786	786 GWINNETT COUNTY WFP (Lanier)	Distribution	Unattended	115.00	25.00		50.00	2	
787		Distribution	Unattended	25.00	4.00		30.00	2	

	787 GWINNETT COUNTY WFP (Shoal Creek)								
788	788 GWINNETT COUNTY WFP (Shoal Creek)	Distribution	Unattended	115.00	25.00		50.00	2	
789	789 GWINNETT STREET	Distribution	Unattended	115.00	13.80		22.40	1	
790	790 HAHIRA	Distribution	Unattended	115.00	12.00		21.00	2	
791	791 HAIRSTON ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
792	792 HAIRSTON ROAD	Distribution	Unattended	230.00	25.00		60.00	1	
793	793 HAMILTON CROSSING ROAD	Distribution	Unattended	46.00	25.00		7.00	1	
794	794 HAMILTON ROAD	Distribution	Unattended	115.00	25.00		67.20	2	
795	795 HANSON AGGREGATES (Athens)	Distribution	Unattended	46.00	2.40		2.50	3	
796	796 HAPEVILLE	Distribution	Unattended	115.00	20.00		56.00	1	
797	797 HARD LABOR CREEK ESTATES PM	Distribution	Unattended	46.00	12.00		0.25	1	
798	798 HARGROVE ROAD	Distribution	Unattended	115.00	20.00		112.00	2	
799	799 HARMONY BLUE GRANITE #1	Distribution	Unattended	46.00	0.60		0.75	3	
800	800 HARRISON	Distribution	Unattended	46.00	12.00		5.25	1	
801	801 HARTFORD PM	Distribution	Unattended	46.00	12.00		0.25	1	
802	802 HARTSFIELD FIFTH RUNWAY BRIDGE	Distribution	Unattended	115.00	25.00		10.50	1	
803	803 HARTSFIELD JACKSON	Distribution	Unattended	115.00	20.00		80.00	2	
804	804 HARTSFIELD JACKSON	Distribution	Unattended	115.00	20.00		60.00	1	
805	805 HARTWELL	Distribution	Unattended	115.00	12.00		50.00	2	
806	806 HATCH	Generation	Attended	500.00	25.00		1200.00	3	
807	807 HATCH	Generation	Attended	25.00	2.40		25.00	1	
808	808 HATCH	Generation	Attended	230.00	4.00		44.00	1	
809	809 HATCH	Generation	Attended	4.00	0.60		1.34	2	
810	810 HATCH	Generation	Attended	230.00			1200.00	1	
811	811 HATCH	Generation	Attended	0.60	0.21		0.17	1	
812	812 HATCH	Generation	Attended	25.00	4.00		28.00	1	
813	813 HATCH	Generation	Attended	25.00	4.00		35.00	1	
814	814 HATCH	Generation	Attended	25.00	4.00		33.60	1	
815	815 HATCH SITE #1	Distribution	Unattended	115.00	12.00		21.00	2	
816	816 HATCH SITE #2	Distribution	Unattended	230.00	12.00		25.00	1	
817	817 HAWTHORNE	Distribution	Unattended	115.00	12.00		22.40	1	
818	818 HAWTHORNE	Distribution	Unattended	115.00	12.00		33.60	1	
819	819 HAZLEHURST PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
820	820 HAZLEHURST PRIMARY	Transmission	Unattended	115.00	46.00		50.00	1	

821	821 HAZLEHURST WOOD PELLETS	Distribution	Unattended	115.00	12.00		25.00	1	
822	822 HEMPHILL WATER TREATMENT	Distribution	Unattended	115.00	4.00		50.00	2	
823	823 HERCULES (Covington)	Distribution	Unattended	115.00	12.00		44.80	2	
824	824 HERCULES (Savannah)	Distribution	Unattended	13.20	0.48		2.50	3	
825	825 HERITAGE HILLS PM	Distribution	Unattended	46.00	12.00		0.25	1	
826	826 HERRINGTON ROAD	Distribution	Unattended	115.00	25.00		60.00	1	
827	827 HERTY LABS	Distribution	Unattended	46.00	4.00		16.00	1	
828	828 HIGHTOWER	Distribution	Unattended	115.00	20.00		56.00	1	
829	829 HIGHTOWER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
830	830 HIGHWAY 106 PM (Commerce)	Distribution	Unattended	46.00	12.00		0.25	1	
831	831 HIGHWAY 16 PM (Eatonton)	Distribution	Unattended	46.00	12.00		0.84	3	
832	832 HIGHWAY 51 PM (Hartwell)	Distribution	Unattended	46.00	12.00		0.25	1	
833	833 HIGHWAY 515 PM (Ellijay)	Distribution	Unattended	46.00	12.00		0.25	1	
834	834 HILL STREET	Distribution	Unattended	230.00	20.00		180.00	3	
835	835 HINESVILLE PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
836	836 HINESVILLE PRIMARY	Transmission	Unattended	115.00	12.00		22.40	1	
837	837 HIRAM	Distribution	Unattended	46.00	12.00		5.25	1	
838	838 HIRAM SUDIE PM Retired	Distribution	Unattended	46.00	12.00		0.25	1	
839	839 HOBBS PM	Distribution	Unattended	46.00	12.00		0.25	1	
840	840 HOGANSVILLE	Distribution	Unattended	115.00	12.00		10.50	1	
841	841 HOLLY DRIVE INDUSTRIAL	Distribution	Unattended	115.00	13.80		44.80	2	
842	842 HOLLY SPRINGS	Distribution	Unattended	115.00	25.00		50.00	1	
843	843 HOMERVILLE	Distribution	Unattended	115.00	25.00		25.00	1	
844	844 HON	Distribution	Unattended	46.00	0.48		1.68	1	
845	845 HONDA	Distribution	Unattended	115.00	12.00		42.00	4	
846	846 HORSELEG CREEK	Distribution	Unattended	115.00	12.00		10.50	1	
847	847 HOUSTON CHAPEL	Distribution	Unattended	115.00	20.00		100.00	2	
848	848 HUB JUNCTION PM	Distribution	Unattended	46.00	12.00		0.25	1	
849	849 HUDSON WIRE	Distribution	Unattended	46.00	0.48		2.10	1	
850	850 HUDSON WIRE	Distribution	Unattended	46.00	0.48		1.12	1	
851	851 HUNTER FIELD	Distribution	Unattended	46.00	13.80		50.00	2	
852	852 HUNTSMAN PIGMENTS	Distribution	Unattended	115.00	25.00		10.50	1	
853	853 HUSQVARNA	Distribution	Unattended	46.00	0.48		3.50	1	
854	854 HUSQVARNA	Distribution	Unattended	46.00	0.48		2.80	1	
855	855 HUTCHINSON ISLAND	Distribution	Unattended	115.00	25.00		50.00	2	
856	856 IDEAL WOOD PELLETS PD	Distribution	Unattended	46.00	25.00		5.00	1	

857	857 IDLEWOOD	Distribution	Unattended	230.00	20.00		56.00	1	
858	858 INDIAN TRACE PM	Distribution	Unattended	46.00	12.00		0.25	1	
859	859 INDUSTRIAL BOULEVARD	Distribution	Unattended	115.00	12.00		22.40	1	
860	860 INDUSTRIAL PARK DRIVE	Distribution	Unattended	46.00	0.48		2.80	1	
861	861 INLAND ROME	Distribution	Unattended	115.00	13.80		21.00	2	
862	862 INLAND ROME	Distribution	Unattended	115.00	13.80		67.20	3	
863	863 INTERFOR (Baxley)	Distribution	Unattended	46.00	4.00		14.00	2	
864	864 INTERNATIONAL PAPER (Gordon)	Distribution	Unattended	115.00	4.00		15.00	2	
865	865 INTERNATIONAL PLAYTEX	Distribution	Unattended	46.00	0.60		2.00	3	
866	866 INTERSTATE CENTRE	Distribution	Unattended	115.00	25.00		25.00	1	
867	867 INTERSTATE CENTRE	Distribution	Unattended	115.00	13.80		14.00	1	
868	868 INTERSTATE PAPER	Distribution	Unattended	115.00	12.00		33.60	1	
869	869 INTERSTATE PAPER	Distribution	Unattended	115.00	12.00		21.00	2	
870	870 INTERSTATE PAPER	Distribution	Unattended	115.00	12.00		67.20	2	
871	871 INTRENCHMENT CREEK SEWAGE	Distribution	Unattended	20.00	4.00		4.69	1	
872	872 ISSAC HALL PM	Distribution	Unattended	46.00	12.00		0.25	1	
873	873 J. C. PENNEY	Distribution	Unattended	115.00	12.00		25.00	1	
874	874 J. M. HUBER (Commerce)	Distribution	Unattended	115.00	12.00		10.50	1	
875	875 J. M. HUBER (McIntyre)	Distribution	Unattended	115.00	12.00		10.50	1	
876	876 J. M. HUBER (Reids)	Distribution	Unattended	46.00	4.00		12.50	2	
877	877 J. M. HUBER MINE #1 (Marble Hill) PM	Distribution	Unattended	46.00	12.00		0.75	3	
878	878 J. R. YOUNG PM	Distribution	Unattended	46.00	12.00		0.25	1	
879	879 J. T. RYERSON & SON #1	Distribution	Unattended	46.00	25.00		10.50	2	
880	880 J. T. RYERSON & SON #2	Distribution	Unattended	46.00	0.48		2.80	1	
881	881 J. WILLFORD PM (Vesta)	Distribution	Unattended	46.00	12.00		0.25	1	
882	882 JACK MCDONOUGH	Generation	Attended	230.00	13.80		60.00	1	
883	883 JACK MCDONOUGH	Generation	Attended	115.00	13.20		98.00	1	
884	884 JACK MCDONOUGH CC #4	Generation	Attended	230.00			345.00	1	
885	885 JACK MCDONOUGH CC #4	Generation	Attended	230.00			432.00	1	
886	886 JACK MCDONOUGH CC #4	Generation	Attended	115.00			345.00	1	
887	887 JACK MCDONOUGH CC #5	Generation	Attended	230.00			345.00	1	
888	888 JACK MCDONOUGH CC #5	Generation	Attended	25.00			50.00	2	
889	889 JACK MCDONOUGH CC #5	Generation	Attended	230.00			432.00	1	
890	890 JACK MCDONOUGH CC #5	Generation	Attended	115.00			345.00	1	
891	891 JACK MCDONOUGH CC #6	Generation	Attended	115.00	4.00		25.00	1	
892	892 JACK MCDONOUGH CC #6	Generation	Attended	230.00			432.00	1	

893	893 JACK MCDONOUGH CC #6	Generation	Attended	230.00			690.00	2	
894	894 JACKSON COUNTY HEALTH CENTER PM	Distribution	Unattended	46.00	12.00		0.25	1	
895	895 JACKSON COUNTY SENIOR CITIZENS PM	Distribution	Unattended	46.00	12.00		0.25	1	
896	896 JAMES SHORT PM	Distribution	Unattended	46.00	12.00		0.25	1	
897	897 JAMESTOWN	Distribution	Unattended	115.00	12.00		22.40	1	
898	898 JEFFERSONVILLE	Distribution	Unattended	115.00	12.00		10.50	1	
899	899 JEFFERSONVILLE	Distribution	Unattended	115.00	12.00		44.80	2	
900	900 JEKYLL ISLAND	Distribution	Unattended	46.00	12.00		9.37	2	
901	901 JEKYLL ISLAND	Distribution	Unattended	46.00	12.00		7.00	1	
902	902 JENNINGS PM	Distribution	Unattended	46.00	12.00		0.25	1	
903	903 JERED BROWN BROTHERS	Distribution	Unattended	115.00	4.00		11.20	2	
904	904 JESSIE PORCH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
905	905 JESUP CITY	Distribution	Unattended	115.00	12.00		22.40	1	
906	906 JEWELL	Distribution	Unattended	46.00	12.00		5.25	1	
907	907 JIMMY CARGILL PM	Distribution	Unattended	46.00	12.00		0.25	1	
908	908 JOHNS CREEK	Distribution	Unattended	230.00	12.00		40.00	1	
909	909 JOHNS CREEK	Distribution	Unattended	230.00	25.00		60.00	1	
910	910 JOHNS CREEK	Distribution	Unattended	230.00	12.00		67.20	2	
911	911 JOHNS CREEK	Distribution	Unattended	230.00	25.00		56.00	1	
912	912 JOHNS MANVILLE INTERNATIONAL	Distribution	Unattended	115.00	4.00		25.00	1	
913	913 JOHNS MANVILLE INTERNATIONAL	Distribution	Unattended	115.00	4.00		44.80	2	
914	914 JOHNSON FERRY ROAD	Distribution	Unattended	230.00	20.00		56.00	1	
915	915 JONES CREEK	Distribution	Unattended	115.00	12.00		67.20	2	
916	916 JONESBORO	Distribution	Unattended	115.00	25.00		56.44	1	
917	917 JUNCTION CITY	Distribution	Unattended	46.00	12.00		4.20	1	
918	918 JUNCTION CITY	Distribution	Unattended	46.00	12.00		5.25	1	
919	919 JUNCTION CITY MINING PD	Distribution	Unattended	46.00	12.00		2.50	1	
920	920 JUNCTION CITY MINING #3 PD	Distribution	Unattended	46.00	4.00		2.50	1	
921	921 KAMIN (Wrens)	Distribution	Unattended	46.00	12.00		5.25	1	
922	922 KAMIN (Wrens)	Distribution	Unattended	46.00	4.00		7.00	1	
923	923 KAMIN (Wrens)	Distribution	Unattended	46.00	4.00		5.25	1	
924	924 KAMIN MINE (Thomson)	Distribution	Unattended	46.00	4.00		10.50	2	
925	925 KAOLIN	Transmission	Unattended	115.00	46.00		25.00	1	
926	926 KAOLIN	Transmission	Unattended	115.00	25.00		33.60	1	

927	927 KATHWOOD DRIVE	Distribution	Unattended	115.00	12.00		40.00	1	
928	928 KEDRON	Distribution	Unattended	115.00	12.00		25.00	1	
929	929 KEITH WHITE PD	Distribution	Unattended	46.00	12.00		2.50	1	
930	930 KELLOGGS SNACKS	Distribution	Unattended	13.80	0.48		3.50	1	
931	931 KENNESAW	Distribution	Unattended	115.00	25.00		40.00	1	
932	932 KENNESAW	Distribution	Unattended	115.00	12.00		33.60	1	
933	933 KERRY #2 PD	Distribution	Unattended	46.00	0.48		2.50	1	
934	934 KERRY #3 PD	Distribution	Unattended	46.00	0.48		2.50	1	
935	935 KERRY #4 PD	Distribution	Unattended	46.00	0.48		2.50	1	
936	936 KETTLE CREEK	Distribution	Unattended	115.00	12.00		44.80	2	
937	937 KEYSTONE MEMORIALS	Distribution	Unattended	46.00	0.48		2.00	6	
938	938 KIA MOTORS	Distribution	Unattended	115.00	13.80		100.00	2	
939	939 KIA MOTORS	Distribution	Unattended	115.00	13.80		22.40	1	
940	940 KIMBALL BRIDGE	Distribution	Unattended	230.00	25.00		56.00	1	
941	941 KIMBALL BRIDGE	Distribution	Unattended	230.00	25.00		60.00	1	
942	942 KIMBALL BRIDGE	Distribution	Unattended	230.00	12.00		40.00	1	
943	943 KINCHAFOONEE	Distribution	Unattended	115.00	12.00		7.00	1	
944	944 KINCHAFOONEE	Distribution	Unattended	115.00	46.00		25.00	1	
945	945 KING AMERICA	Distribution	Unattended	115.00	12.00		7.00	1	
946	946 KING SPRINGS ROAD	Distribution	Unattended	115.00	20.00		120.00	2	
947	947 KING SPRINGS ROAD	Distribution	Unattended	25.00	20.00		25.00	1	
948	948 KING STREET	Distribution	Unattended	115.00	25.00		33.60	1	
949	949 KING STREET	Distribution	Unattended	115.00	25.00		33.60	1	
950	950 KINGS BAY SOLAR	Generation	Attended	230.00	34.50		40.00	1	
951	951 KINGSLAND	Distribution	Unattended	115.00	12.00		44.80	2	
952	952 KINGSLAND	Distribution	Unattended	115.00	12.00		25.00	1	
953	953 KINGSTON	Distribution	Unattended	230.00	25.00		40.00	1	
954	954 KIOKEE ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
955	955 KIRKHILL MANUFACTURING	Distribution	Unattended	46.00	2.40		5.00	3	
956	956 KIRKWOOD	Distribution	Unattended	115.00	20.00		60.00	1	
957	957 KOYO BEARING	Distribution	Unattended	46.00	12.00		7.00	1	
958	958 KRAFT 115	Transmission	Attended	7.62	0.12			2	
959	959 L. C. WHIGHAM PM	Distribution	Unattended	46.00	12.00		0.25	1	
960	960 L. L. BARNES PM	Distribution	Unattended	46.00	12.00		0.25	1	
961	961 LAFARGE AGGREGATES #1 Douglasville	Distribution	Unattended	46.00	0.48		2.24	2	
962	962 LAGRANGE	Distribution	Unattended	115.00	46.00		50.00	2	

963	963 LAGRANGE	Distribution	Unattended	115.00	12.00		33.60	1
964	964 LAKE JENNIFER PM	Distribution	Unattended	46.00	12.00		0.25	1
965	965 LAKE LANIER	Distribution	Unattended	115.00	25.00		33.33	1
966	966 LAKE LANIER	Distribution	Unattended	115.00	25.00		44.80	2
967	967 LAKE OCONEE	Distribution	Unattended	115.00	25.00		50.00	1
968	968 LAKE OCONEE	Distribution	Unattended	115.00	25.00		33.30	1
969	969 LAKE RIDGE PARKWAY	Distribution	Unattended	115.00	4.00		10.50	1
970	970 LAKE SINCLAIR	Distribution	Unattended	115.00	25.00		10.50	1
971	971 LAKE SUSIE PM	Distribution	Unattended	46.00	12.00		0.25	1
972	972 LAKE TYRONE PD	Distribution	Unattended	46.00	25.00		5.00	1
973	973 LAKELAND	Distribution	Unattended	115.00	12.00		21.00	2
974	974 LAKELAND	Distribution	Unattended	115.00	12.00		10.50	1
975	975 LAKEWOOD	Distribution	Unattended	115.00	20.00		50.00	1
976	976 LAMKIN SMITH PM	Distribution	Unattended	46.00	12.00		0.25	1
977	977 LAMKIN SMITH PM	Distribution	Unattended	46.00	12.00		0.28	1
978	978 LAMKIN SMITH PM	Distribution	Unattended	46.00	12.00		0.25	1
979	979 LANGBOARD (Quitman)	Distribution	Unattended	115.00	12.00		7.00	1
980	980 LANGBOARD (Quitman)	Distribution	Unattended	115.00	12.00		5.00	1
981	981 LANZATECH	Distribution	Unattended	115.00	25.00		60.00	1
982	982 LAST LAKE	Distribution	Unattended	230.00	12.00		33.60	1
983	983 LAWRENCEVILLE HIGHWAY	Distribution	Unattended	115.00	20.00		60.00	1
984	984 LEARY	Distribution	Unattended	46.00	12.00		4.69	1
985	985 LEE HARRIS PM	Distribution	Unattended	46.00	12.00		0.75	3
986	986 LEESBURG	Distribution	Unattended	115.00	12.00		25.00	1
987	987 LESLIE	Distribution	Unattended	46.00	12.00		5.25	1
988	988 LEWIS DRIVE	Distribution	Unattended	115.00	13.80		80.00	2
989	989 LEWIS SIGN PM	Distribution	Unattended	46.00	0.24		0.03	1
990	990 LEXINGTON COMPONENTS	Distribution	Unattended	46.00	0.48		3.50	1
991	991 LIBERTY	Distribution	Unattended	115.00	13.80		25.00	1
992	992 LIKEN INDUSTRIES	Distribution	Unattended	46.00	0.48		0.50	1
993	993 LILBURN	Distribution	Unattended	115.00	25.00		33.60	1
994	994 LIMESTONE CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1
995	995 LINDALE	Distribution	Unattended	115.00	46.00		25.00	1
996	996 LINDALE	Distribution	Unattended	115.00	12.00		22.40	1
997	997 LINDALE	Distribution	Unattended	115.00	46.00		25.00	1

998	998 LINDBERGH	Distribution	Unattended	230.00	20.00		120.00	2	
999	999 LINWOOD WRF	Distribution	Unattended	115.00	4.00		6.25	1	
1000	1000 LINWOOD WRF	Distribution	Unattended	115.00	12.00		25.00	1	
1001	1001 LIQUID CARBONIC	Distribution	Unattended	13.80	4.00		5.00	1	
1002	1002 LITE-N-TIE (Postell) PM	Distribution	Unattended	46.00	12.00		1.00	3	
1003	1003 LITHONIA	Distribution	Unattended	115.00	25.00		33.60	1	
1004	1004 LITHONIA	Distribution	Unattended	25.00	20.00		33.60	1	
1005	1005 LITHONIA	Distribution	Unattended	115.00	25.00		56.00	1	
1006	1006 LITHONIA LIGHTING	Distribution	Unattended	46.00	12.00		4.69	1	
1007	1007 LITTLE NEW YORK PM	Distribution	Unattended	46.00	12.00		0.25	1	
1008	1008 LITTLE RIVER	Distribution	Unattended	115.00	12.00		10.50	1	
1009	1009 LITTLE RIVER	Distribution	Unattended	115.00	25.00		60.00	1	
1010	1010 LIZELLA	Distribution	Unattended	115.00	12.00		10.50	1	
1011	1011 LLOYD SHOALS	Transmission	Attended	12.00	4.00		5.60	1	
1012	1012 LLOYD SHOALS HYDRO	Generation	Attended	12.00	2.40		10.00	1	
1013	1013 LLOYD SHOALS HYDRO	Generation	Attended	12.00	2.40		12.50	1	
1014	1014 LOCH LAUREL	Distribution	Unattended	115.00	12.00		25.00	1	
1015	1015 LOCKEBY PM	Distribution	Unattended	46.00	7.20		0.25	1	
1016	1016 LOCKHEED MARTIN #1	Distribution	Unattended	115.00	12.00		80.00	2	
1017	1017 LOCKHEED MARTIN #2	Distribution	Unattended	46.00	12.00		5.60	1	
1018	1018 LOCKHEED MARTIN WIND TUNNEL	Distribution	Unattended	115.00	4.00		89.60	4	
1019	1019 LONG CANE	Distribution	Unattended	115.00	25.00		40.00	1	
1020	1020 LOOKOUT VALLEY	Transmission	Unattended	115.00	46.00		60.00	1	
1021	1021 LOOKOUT VALLEY	Transmission	Unattended	115.00	25.00		25.00	1	
1022	1022 LOUISVILLE AREA #3 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1023	1023 LOUISVILLE AREA #7 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1024	1024 LOUISVILLE PRIMARY	Distribution	Unattended	115.00	12.00		10.50	1	
1025	1025 LUCENT TECHNOLOGIES #1 (OFS FITEL)	Distribution	Unattended	115.00	13.80		93.33	2	
1026	1026 LUCENT TECHNOLOGIES #2 (OFS FITEL)	Distribution	Unattended	115.00	13.80		50.00	2	
1027	1027 LUDOWICI PRIMARY	Transmission	Unattended	115.00	12.00		10.50	1	
1028	1028 LUMBER CITY	Distribution	Unattended	46.00	12.00		7.00	1	
1029	1029 LYLE CIRCLE PD	Distribution	Unattended	46.00	25.00		3.75	1	
1030	1030 M A INDUSTRIES	Distribution	Unattended	12.00	0.48		1.50	1	
1031	1031 M&M MARS	Distribution	Unattended	115.00	4.00		10.50	1	
1032	1032 MABLETON	Distribution	Unattended	115.00	25.00		40.00	1	
1033	1033 MABLETON	Distribution	Unattended	115.00	25.00		40.00	1	

1034	1034 MACON COUNTY PRISON #1 PD (South)	Distribution	Unattended	46.00	12.00		2.50	1	
1035	1035 MACON COUNTY PRISON #1 PD (South)	Distribution	Unattended	46.00	12.00		2.50	1	
1036	1036 MADISON	Distribution	Unattended	46.00	12.00		7.00	1	
1037	1037 MADISON	Distribution	Unattended	46.00	12.00		7.00	1	
1038	1038 MADRAS	Distribution	Unattended	115.00	12.00		10.50	1	
1039	1039 MADRAS	Distribution	Unattended	115.00	25.00		25.00	1	
1040	1040 MAGNOLIA	Transmission	Unattended	115.00	13.80		33.60	1	
1041	1041 MAGNOLIA	Transmission	Unattended	46.00	13.80		25.00	1	
1042	1042 MAGNOLIA BLUFF	Distribution	Unattended	25.00	12.00		7.00	1	
1043	1043 MAGNOLIA BLUFF	Distribution	Unattended	115.00	12.00		10.50	1	
1044	1044 MAGNOLIA MANOR	Distribution	Unattended	46.00	0.48		1.00	2	
1045	1045 MAGNOLIA MANOR	Distribution	Unattended	46.00	0.48		2.24	4	
1046	1046 MAGNOLIA PARK	Distribution	Unattended	115.00	12.00		22.40	1	
1047	1047 MAGNOLIA PARK	Distribution	Unattended	115.00	12.00		20.00	1	
1048	1048 MAGNOLIA ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1049	1049 MAIN STREET PD	Distribution	Unattended	46.00	12.00		2.50	1	
1050	1050 MALL OF GEORGIA	Distribution	Unattended	115.00	25.00		67.20	2	
1051	1051 MANCHESTER	Distribution	Unattended	115.00	25.00		42.00	4	
1052	1052 MANN ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1053	1053 MANSFIELD	Distribution	Unattended	46.00	25.00		21.00	3	
1054	1054 MAR-JAC POULTRY #1	Distribution	Unattended	46.00	0.48		3.50	1	
1055	1055 MARBLE VALLEY	Distribution	Unattended	46.00	12.00		7.00	1	
1056	1056 MARION SPENCE ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1057	1057 MARK EVANS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1058	1058 MARK GLASS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1059	1059 MARK GLASS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1060	1060 MARSHALLVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
1061	1061 MARTA ANNEX	Distribution	Unattended	20.00	0.48		4.69	1	
1062	1062 MARTIN HEIGHTS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1063	1063 MARTIN MARIETTA (Camak)	Distribution	Unattended	46.00	2.40		4.50	3	
1064	1064 MARTIN MARIETTA (Gray)	Distribution	Unattended	46.00	2.40		6.25	1	
1065	1065 MARTIN MARIETTA (Johns Creek)	Distribution	Unattended	115.00	25.00		10.50	1	
1066	1066 MARTIN MARIETTA (Junction City)	Distribution	Unattended	46.00	12.00		5.25	1	
1067	1067 MARTIN MARIETTA (Martinez)	Distribution	Unattended	13.80	2.40		5.00	1	
1068	1068 MARTIN MARIETTA (Tyrone)	Distribution	Unattended	46.00	2.40		4.17	5	

1069	1069 MARTIN MARIETTA (Warrenton)	Distribution	Unattended	46.00	12.00		2.50	3	
1070	1070 MARVIN GRIFFIN ROAD	Distribution	Unattended	115.00	13.80		33.60	1	
1071	1071 MARVIN GRIFFIN ROAD	Distribution	Unattended	115.00	13.80		33.00	1	
1072	1072 MCBEAN ROAD	Distribution	Unattended	115.00	13.80		25.00	1	
1073	1073 MCBEAN ROAD	Distribution	Unattended	115.00	13.80		22.40	1	
1074	1074 MCCREE PM	Distribution	Unattended	46.00	12.00		0.56	2	
1075	1075 MCCREE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1076	1076 MCDONOUGH	Distribution	Unattended	115.00	12.00		22.40	1	
1077	1077 MCDONOUGH	Distribution	Unattended	115.00	25.00		40.00	1	
1078	1078 MCDONOUGH	Distribution	Unattended	115.00	12.00		25.00	1	
1079	1079 MCDONOUGH CONSTRUCTION	Distribution	Unattended	20.00	0.28		0.34	3	
1080	1080 MCGRAU FORD	Transmission	Unattended	13.80	0.48		1.00	1	
1081	1081 MCINTOSH	Generation	Unattended	115.00	25.00		25.00	1	
1082	1082 MCINTOSH	Generation	Unattended	115.00	25.00		40.00	1	
1083	1083 MCINTOSH CC	Generation	Attended	230.00			250.00	1	
1084	1084 MCINTOSH CC	Generation	Attended	230.00			670.00	2	
1085	1085 MCINTOSH CC	Generation	Attended	230.00			645.00	3	
1086	1086 MCINTOSH CT	Generation	Attended	13.80	0.48	0	17.94	3	
1087	1087 MCINTOSH CT	Generation	Attended	13.80	0.48	0	2.00	1	
1088	1088 MCINTOSH CT	Generation	Attended	13.80	13.80		5.98	1	
1089	1089 MCINTOSH CT	Generation	Attended	13.80	0.48	0	4.50	3	
1090	1090 MCINTOSH CT 5 AND 6	Generation	Attended	230.00	13.80		880.00	4	
1091	1091 MCINTOSH TRAIL	Distribution	Unattended	115.00	25.00		25.00	1	
1092	1092 MCMANUS	Generation	Attended	2.40	0.48		0.56	1	
1093	1093 MCMANUS	Generation	Attended	115.00	13.20		56.00	1	
1094	1094 MCMANUS	Generation	Attended	13.80	2.40		3.22	1	
1095	1095 MCMANUS	Generation	Attended	2.40	0.48		2.24	1	
1096	1096 MCMANUS	Generation	Attended	115.00	13.20		120.00	2	
1097	1097 MCMANUS	Generation	Attended	13.80	2.40		4.48	2	
1098	1098 MCMANUS	Generation	Attended	230.00	13.20		396.00	3	
1099	1099 MCMANUS	Generation	Attended	13.80	2.40		2.50	1	
1100	1100 MCMANUS	Generation	Attended	13.80	2.40		3.36	2	
1101	1101 MCMANUS	Generation	Attended	13.80	0.48		3.86	3	
1102	1102 MCMANUS	Generation	Attended	2.40	0.48		0.30	1	
1103	1103 MCPHERSON MANUFACTURING	Distribution	Unattended	46.00	0.48		3.50	1	

1104	1104 MCRAE	Transmission	Unattended	115.00	46.00		25.00	1	
1105	1105 MCRAE #2	Distribution	Unattended	46.00	12.00		5.25	1	
1106	1106 MCRAE #2	Distribution	Unattended	46.00	12.00		4.69	1	
1107	1107 MEADOWS LAKE #1 PM	Distribution	Unattended	46.00	12.00		0.67	2	
1108	1108 MEADOWS SUBDIVISION PM	Distribution	Unattended	46.00	12.00		0.25	1	
1109	1109 MEDUSA PORTLAND CEMENT	Distribution	Unattended	115.00	4.00		37.50	4	
1110	1110 MEDUSA PORTLAND CEMENT	Distribution	Unattended	115.00	4.00		25.00	1	
1111	1111 MEDUSA PORTLAND CEMENT #2	Distribution	Unattended	46.00	4.00		1.67	5	
1112	1112 MEDUSA PORTLAND CEMENT #3	Distribution	Unattended	46.00	2.40		1.50	3	
1113	1113 MEIGS	Distribution	Unattended	46.00	12.00		5.25	1	
1114	1114 MELDRIM	Transmission	Unattended	115.00	13.80		25.00	1	
1115	1115 MELDRIM	Transmission	Unattended	115.00	46.00	13	112.00	1	
1116	1116 MELDRIM	Transmission	Unattended	115.00	13.80		22.40	1	
1117	1117 MENLO	Distribution	Unattended	46.00	12.00		14.00	2	
1118	1118 MERIWETHER PARK	Distribution	Unattended	115.00	25.00		40.00	1	
1119	1119 MERIWETHER ROAD	Distribution	Unattended	115.00	12.00		50.00	2	
1120	1120 METAL PRODUCTS #1	Distribution	Unattended	12.00	0.48		1.12	1	
1121	1121 METTER	Distribution	Unattended	115.00	12.00		25.00	1	
1122	1122 METTER AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1123	1123 METTER PRIMARY	Distribution	Unattended	115.00	25.00		25.00	1	
1124	1124 METTER PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1125	1125 MIDVILLE	Distribution	Unattended	46.00	12.00		5.00	6	
1126	1126 MILL CITY SEWAGE PM	Distribution	Unattended	46.00	12.00		0.50	2	
1127	1127 MILL CITY SEWAGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1128	1128 MILLEDGEVILLE	Distribution	Unattended	115.00	46.00		25.00	1	
1129	1129 MILLEDGEVILLE	Distribution	Unattended	115.00	12.00		50.00	2	
1130	1130 MILLEN	Distribution	Unattended	115.00	12.00		25.00	1	
1131	1131 MILLEN AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1132	1132 MILLEN AREA #3 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1133	1133 MILLEN PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1134	1134 MILLHAVEN ANNEX	Transmission	Unattended	115.00	13.80		25.00	1	
1135	1135 MILLHAVEN ANNEX	Transmission	Unattended	115.00	46.00		112.00	1	
1136	1136 MILLIKEN (Alma)	Distribution	Unattended	115.00	4.00		37.50	4	
1137		Distribution	Unattended	46.00	0.60		3.50	1	

	1137 MILLIKEN (Duncan Stewart) Lagrange							
1138	1138 MILLIKEN (Kingsley Mill) Thomson	Distribution	Unattended	115.00	4.00		22.40	1
1139	1139 MILLIKEN (Lagrange)	Distribution	Unattended	115.00	12.00		44.80	2
1140	1140 MILLIKEN (Lagrange)	Distribution	Unattended	115.00	12.00		22.40	1
1141	1141 MILLIKEN (New Holland) Gainesville	Distribution	Unattended	46.00	0.60		7.00	1
1142	1142 MILLIKEN (New Holland) Gainesville	Distribution	Unattended	46.00	0.60		14.00	2
1143	1143 MILLIKEN (Newton Mill)	Distribution	Unattended	46.00	0.60		3.50	1
1144	1144 MILLIKEN (Pine Mountain)	Distribution	Unattended	25.00	0.60		3.50	1
1145	1145 MILLIKEN (Pine Mountain)	Distribution	Unattended	25.00	0.60		4.20	1
1146	1146 MILLIRONS ROAD	Distribution	Unattended	115.00	12.00		33.60	1
1147	1147 MILLIRONS ROAD	Distribution	Unattended	115.00	12.00		22.40	1
1148	1148 MINOLA DRIVE	Distribution	Unattended	230.00	20.00		120.00	2
1149	1149 MISSION POND	Distribution	Attended	115.00	34.50		55.00	1
1150	1150 MITCHELL 115	Transmission	Unattended	115.00	46.00		25.00	1
1151	1151 MITCHELL 115	Transmission	Unattended	115.00	12.00		10.00	1
1152	1152 MODULAR CONTAINER SYSTEMS	Distribution	Unattended	46.00	0.48		1.12	1
1153	1153 MOHAWK INDUSTRIES (East Dublin)	Distribution	Unattended	46.00	12.00		7.00	1
1154	1154 MOHAWK INDUSTRIES (Lyerly)	Distribution	Unattended	46.00	4.00		7.00	1
1155	1155 MOHAWK INDUSTRIES (Summerville)	Distribution	Unattended	115.00	25.00		80.00	2
1156	1156 MOLENA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1
1157	1157 MOLENA PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1
1158	1158 MONK ROAD	Distribution	Unattended	115.00	12.00		31.50	3
1159	1159 MONROE	Distribution	Unattended	115.00	25.00		44.80	2
1160	1160 MONROE	Distribution	Unattended	115.00	46.00		25.00	1
1161	1161 MONROE INDUSTRIAL PD	Distribution	Unattended	46.00	0.48		2.50	1
1162	1162 MONTEZUMA	Distribution	Unattended	115.00	12.00		10.50	1
1163	1163 MONTEZUMA	Distribution	Unattended	115.00	12.00		10.50	1
1164	1164 MONTGOMERYVILLE	Distribution	Unattended	46.00	12.00		7.00	1
1165	1165 MORELAND AVENUE	Distribution	Unattended	115.00	20.00		120.00	2
1166	1166 MORELAND WAY	Distribution	Unattended	115.00	20.00		60.00	1
1167	1167 MORGAN	Distribution	Unattended	46.00	12.00		1.50	3
1168	1168 MORGAN FALLS	Distribution	Unattended	115.00	20.00		40.00	1
1169	1169 MORGAN FALLS	Distribution	Unattended	115.00	25.00		56.00	1

1170	1170 MORGAN FALLS HYDRO	Generation	Attended	20.00	4.00		15.00	2	
1171	1171 MORGAN PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1172	1172 MORGANVILLE	Distribution	Unattended	46.00	12.00		10.50	2	
1173	1173 MORGANVILLE	Distribution	Unattended	161.00	46.00		22.40	1	
1174	1174 MORNINGSIDE	Distribution	Unattended	230.00	20.00		56.00	1	
1175	1175 MOULTRIE	Distribution	Unattended	115.00	46.00		25.00	1	
1176	1176 MOULTRIE	Distribution	Unattended	115.00	12.00		10.50	1	
1177	1177 MOULTRIE	Distribution	Unattended	115.00	25.00		40.00	1	
1178	1178 MOULTRIE	Distribution	Unattended	115.00	12.00		10.50	1	
1179	1179 MOUNT VERNON	Distribution	Unattended	115.00	12.00		10.50	1	
1180	1180 MOUNT VERNON MILLS (Alto)	Distribution	Unattended	115.00	12.00		31.50	3	
1181	1181 MOUNT VERNON MILLS (Cleveland)	Distribution	Unattended	25.00	0.60		5.60	2	
1182	1182 MOUNT VERNON MILLS (Trion)	Distribution	Unattended	115.00	12.00		44.80	2	
1183	1183 MOUNT ZION	Distribution	Unattended	46.00	12.00		1.50	3	
1184	1184 MOUNTAIN HILL	Distribution	Unattended	115.00	25.00		10.50	1	
1185	1185 MOUNTAIN SPRINGS #1 PM	Distribution	Unattended	46.00	12.00		0.33	1	
1186	1186 MOUNTAIN VIEW	Distribution	Unattended	115.00	25.00		44.80	2	
1187	1187 MOUNTAIN VIEW	Distribution	Unattended	115.00	20.00		50.00	1	
1188	1188 MOUNTAIN VIEW	Distribution	Unattended	115.00	20.00		40.00	1	
1189	1189 MRS. SMITHS BAKERIES	Distribution	Unattended	20.00	0.48		3.50	1	
1190	1190 MRS. SMITHS BAKERIES	Distribution	Unattended	20.00	0.48		3.50	1	
1191	1191 MUD CREEK	Distribution	Unattended	115.00	12.00		22.40	1	
1192	1192 MULKEY ROAD	Distribution	Unattended	115.00	25.00		22.40	1	
1193	1193 MULLITE #2	Distribution	Unattended	115.00	46.00		25.00	1	
1194	1194 MULLITE #2	Distribution	Unattended	115.00	4.00		21.00	2	
1195	1195 MURRAY LAKE	Distribution	Unattended	20.00	12.00		22.40	1	
1196	1196 MURRAY LAKE	Distribution	Unattended	115.00	12.00		22.40	1	
1197	1197 MURRAY LAKE	Distribution	Unattended	115.00	20.00		56.00	1	
1198	1198 MYSTERY VALLEY	Distribution	Unattended	115.00	25.00		120.00	2	
1199	1199 NACOOCHEE	Generation	Attended	46.00			7.00	1	
1200	1200 NACOOCHEE	Generation	Attended	46.00	7.20		1.67	2	
1201	1201 NASHVILLE #1	Distribution	Unattended	115.00	12.00		10.50	1	
1202	1202 NASHVILLE #1	Distribution	Unattended	115.00	12.00		9.38	1	
1203	1203 NASHVILLE MILLS ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
1204	1204 NATIONAL BEEF	Distribution	Unattended	46.00	0.48		2.10	1	

1205	1205 NATIONAL BEEF	Distribution	Unattended	46.00	0.48		2.10	1	
1206	1206 NECO	Distribution	Unattended	115.00	13.80		22.40	1	
1207	1207 NECO	Distribution	Unattended	115.00	13.80		40.00	1	
1208	1208 NEW RIVERSIDE OCHRE	Distribution	Unattended	46.00	2.40		1.50	3	
1209	1209 NEWELL RECYCLING #1 (East Point)	Distribution	Unattended	20.00	4.00		5.00	1	
1210	1210 NEWELL RECYCLING (Norcross)	Transmission	Unattended	115.00	4.00		7.00	1	
1211	1211 NEWTON	Distribution	Unattended	46.00	12.00		4.20	1	
1212	1212 NIPPER PM	Distribution	Unattended	46.00	12.00		0.25	1	
1213	1213 NORDIC COLD STORAGE #2 (Doraville)	Distribution	Unattended	46.00	0.48		1.68	1	
1214	1214 NORDIC COLD STORAGE (Doraville)	Distribution	Unattended	46.00	0.48		3.22	3	
1215	1215 NORDIC COLD STORAGE (Hapeville)	Distribution	Unattended	20.00	0.48		2.00	1	
1216	1216 NORMAN PARK ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1217	1217 NORTH ATHENS	Distribution	Unattended	115.00	12.00		80.00	2	
1218	1218 NORTH AWRF	Distribution	Unattended	115.00	12.00		21.00	2	
1219	1219 NORTH CLARKESVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
1220	1220 NORTH COLUMBUS	Distribution	Unattended	115.00	12.00		50.00	2	
1221	1221 NORTH CONYERS	Distribution	Unattended	115.00	12.00		50.00	2	
1222	1222 NORTH DRUID HILLS	Distribution	Unattended	115.00	20.00		40.00	1	
1223	1223 NORTH DRUID HILLS	Distribution	Unattended	115.00	20.00		50.00	1	
1224	1224 NORTH DRUID HILLS	Distribution	Unattended	115.00	20.00		60.00	1	
1225	1225 NORTH FAIRMOUNT	Distribution	Unattended	115.00	12.00		22.40	1	
1226	1226 NORTH FORK	Distribution	Unattended	230.00	20.00		56.00	1	
1227	1227 NORTH GRIFFIN	Distribution	Unattended	115.00	12.00		33.60	1	
1228	1228 NORTH HIGHLANDS	Generation	Attended	12.00	4.00		14.00	1	
1229	1229 NORTH HIGHLANDS	Generation	Attended	12.00	4.00		23.00	1	
1230	1230 NORTH JEFFERSON	Distribution	Unattended	115.00	25.00		25.00	1	
1231	1231 NORTH JEFFERSON	Distribution	Unattended	115.00	46.00		50.00	1	
1232	1232 NORTH JEFFERSON	Distribution	Unattended	115.00	12.00		25.00	1	
1233	1233 NORTH KEITHSBURG	Distribution	Unattended	115.00	25.00		67.20	2	
1234	1234 NORTH KITE	Distribution	Unattended	46.00	12.00		5.25	1	
1235	1235 NORTH MACON	Distribution	Unattended	115.00	12.00		44.80	2	
1236	1236 NORTH MARTIN	Distribution	Unattended	115.00	12.00		10.50	1	
1237	1237 NORTH MCRAE	Distribution	Unattended	46.00	12.00		10.50	1	
1238	1238 NORTH METTER	Distribution	Unattended	46.00	12.00		6.25	1	
1239	1239 NORTH MILLEDGEVILLE	Distribution	Unattended	115.00	12.00		44.80	2	

1240	1240 NORTH MONTICELLO	Transmission	Unattended	230.00	69.00	13	60.00	1	
1241	1241 NORTH OCONEE WRF	Distribution	Unattended	115.00	12.00		10.50	1	
1242	1242 NORTH RIVERSIDE	Distribution	Unattended	115.00	12.00		80.00	2	
1243	1243 NORTH ROCKMART	Distribution	Unattended	115.00	12.00		33.60	1	
1244	1244 NORTH SHALLOWFORD ROAD	Distribution	Unattended	115.00	20.00		60.00	1	
1245	1245 NORTH SPRINGS	Distribution	Unattended	230.00	20.00		56.00	1	
1246	1246 NORTH STATESBORO	Distribution	Unattended	115.00	12.00		25.00	1	
1247	1247 NORTH STATESBORO	Distribution	Unattended	115.00	12.00		22.40	1	
1248	1248 NORTH THOMASTON	Distribution	Unattended	115.00	12.00		25.00	1	
1249	1249 NORTH THOMSON	Distribution	Unattended	46.00	12.00		5.25	1	
1250	1250 NORTH THOMSON	Distribution	Unattended	46.00	25.00		14.00	2	
1251	1251 NORTH TIFTON	Transmission	Unattended	115.00	12.00		25.00	1	
1252	1252 NORTH VALDOSTA	Distribution	Unattended	115.00	12.00		40.00	1	
1253	1253 NORTH VALDOSTA	Distribution	Unattended	115.00	12.00		22.40	1	
1254	1254 NORTHCREST	Distribution	Unattended	115.00	12.00		25.00	1	
1255	1255 NORTHEAST WAYCROSS	Distribution	Unattended	115.00	12.00		44.80	2	
1256	1256 NORTHPARK	Distribution	Unattended	230.00	20.00		60.00	1	
1257	1257 NORTHPARK	Distribution	Unattended	230.00	20.00		112.00	2	
1258	1258 NORTHSIDE DRIVE	Distribution	Unattended	115.00	20.00		50.00	1	
1259	1259 NORTHSIDE DRIVE	Distribution	Unattended	115.00	20.00		112.00	2	
1260	1260 NORTHWEST 115	Distribution	Unattended	230.00	20.00		56.00	1	
1261	1261 NORTHWEST 115	Distribution	Unattended	115.00	20.00		56.00	1	
1262	1262 NORTHWEST PERRY	Distribution	Unattended	115.00	12.00		22.40	1	
1263	1263 NORTHWEST WAYCROSS	Distribution	Unattended	25.00	12.00		7.00	1	
1264	1264 NORTHWEST WAYCROSS	Distribution	Unattended	115.00	12.00		42.00	4	
1265	1265 NORTHWINDS	Distribution	Unattended	230.00	25.00		60.00	1	
1266	1266 NOWHERE ROAD PM	Distribution	Unattended	46.00	12.00			1	
1267	1267 NUTRASWEET	Distribution	Unattended	115.00	13.80		22.40	1	
1268	1268 NUTRASWEET	Distribution	Unattended	115.00	13.80		10.50	1	
1269	1269 NUTRASWEET	Distribution	Unattended	115.00	12.00		25.00	1	
1270	1270 OAK GROVE	Distribution	Unattended	115.00	25.00		33.60	1	
1271	1271 OAK GROVE	Distribution	Unattended	115.00	25.00		40.00	1	
1272	1272 OAK STREET	Distribution	Unattended	115.00	12.00		44.80	2	
1273	1273 OAK STREET	Distribution	Unattended	115.00	12.00		33.00	1	
1274	1274 OAKFIELD PM	Distribution	Unattended	46.00	12.00		0.25	1	

1275	1275 OCHLOCKNEE	Distribution	Unattended	46.00	12.00		5.25	1	
1276	1276 OCHLOCKNEE PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1277	1277 OCMULGEE STREET	Distribution	Unattended	115.00	12.00		25.00	1	
1278	1278 OCMULGEE STREET	Distribution	Unattended	115.00	12.00		33.60	1	
1279	1279 OCONEE PD	Distribution	Unattended	46.00	12.00		2.50	1	
1280	1280 OGLETHORPE MALL	Distribution	Unattended	115.00	13.80		50.00	2	
1281	1281 OHOOPEE RIVER	Distribution	Unattended	115.00	12.00		21.00	2	
1282	1282 OLD ALABAMA ROAD	Distribution	Unattended	230.00	25.00		56.00	1	
1283	1283 OLD ALABAMA ROAD	Distribution	Unattended	230.00	12.00		67.20	2	
1284	1284 OLD ALABAMA ROAD	Distribution	Unattended	230.00	25.00		60.00	1	
1285	1285 OLD DALTON ROAD	Distribution	Unattended	115.00	12.00		20.00	1	
1286	1286 OLD HICKORY	Distribution	Unattended	115.00	12.00		80.00	2	
1287	1287 OLD NATIONAL	Distribution	Unattended	115.00	25.00		56.00	1	
1288	1288 OLD RIVER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1289	1289 OLD SAVANAH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1290	1290 OLIN	Distribution	Unattended	115.00	13.80		10.50	1	
1291	1291 OLIVER DAM HYDRO	Generation	Attended	115.00	7.20		45.00	2	
1292	1292 OLIVER DAM HYDRO	Generation	Attended	115.00	7.20		30.00	1	
1293	1293 OLIVER ROAD	Distribution	Unattended	115.00	12.00		33.60	1	
1294	1294 OPHELIA SMITH PM	Distribution	Unattended					1	
1295	1295 ORANGE	Distribution	Unattended	115.00	25.00		35.87	1	
1296	1296 ORANGE	Distribution	Unattended	115.00	25.00		45.06	1	
1297	1297 ORANGE HILL	Distribution	Unattended	115.00	12.00		25.00	1	
1298	1298 ORCHARD HILL	Distribution	Unattended	69.00	12.00		5.25	1	
1299	1299 OVERLAND TRAIL LAND PM	Distribution	Unattended	46.00	12.00		0.25	1	
1300	1300 OWENS BROCKWAY (Sylvan Road)	Distribution	Unattended	20.00	4.00		25.00	4	
1301	1301 OWENS CORNING FIBERGLASS	Distribution	Unattended	115.00	12.00		44.80	2	
1302	1302 OWENS ILLINOIS (Hamilton Boulevard)	Distribution	Unattended	20.00	0.48		2.58	2	
1303	1303 OWL HEAD #2	Distribution	Unattended	46.00	12.00		0.25	1	
1304	1304 OXFORD ROAD	Distribution	Unattended	115.00	20.00		53.20	1	
1305	1305 PACES FERRY	Distribution	Unattended	115.00	20.00		56.00	1	
1306	1306 PACKAGING CORPORATION (Clyattville)	Distribution	Unattended	69.00	4.00		50.00	2	
1307	1307 PACKAGING CORPORATION (Macon)	Distribution	Unattended	12.00	0.48		3.50	1	
1308		Distribution	Unattended	12.00	0.48		3.50	1	

	1308 PACKAGING CORPORATION (Macon)							
1309	1309 PACTIV #2	Distribution	Unattended	46.00	0.48		2.80	1
1310	1310 PACTIV #2	Distribution	Unattended	46.00	0.48		1.68	1
1311	1311 PACTIV #3 PD	Distribution	Unattended	46.00	0.48		2.50	1
1312	1312 PACTIV #4 PD	Distribution	Unattended	46.00	0.48		2.50	1
1313	1313 PACTIV #6	Distribution	Unattended	46.00	0.48		10.50	3
1314	1314 PACTIV #7	Distribution	Unattended	46.00	0.48		5.60	2
1315	1315 PALM STREET	Distribution	Unattended	115.00	25.00		45.80	2
1316	1316 PALMER CREEK	Distribution	Unattended	230.00	25.00		25.00	1
1317	1317 PALMYRA	Distribution	Unattended	115.00	12.00		25.00	1
1318	1318 PALMYRA	Distribution	Unattended	115.00	25.00		25.00	1
1319	1319 PARK	Distribution	Unattended	115.00	20.00		56.00	1
1320	1320 PARK	Distribution	Unattended	20.00	12.00		44.80	2
1321	1321 PARKDALE	Distribution	Unattended	115.00	12.00		44.80	2
1322	1322 PARKENSON CHURCH ROAD PM	Distribution	Unattended	46.00	12.00		0.50	2
1323	1323 PARKENSON CHURCH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1
1324	1324 PARKWAY	Distribution	Unattended	115.00	12.00		67.20	2
1325	1325 PASCOE STEEL	Distribution	Unattended	12.00	0.48		1.50	1
1326	1326 PATRIOTS PARK	Distribution	Unattended	115.00	12.00		50.00	2
1327	1327 PATTON SEED PM	Distribution	Unattended	46.00	12.00		0.75	3
1328	1328 PAUL WINNIE PM	Distribution	Unattended	46.00	12.00		0.25	1
1329	1329 PAUL WINNIE PM	Distribution	Unattended	46.00	12.00		0.28	1
1330	1330 PCS NITROGEN	Distribution	Unattended	115.00	13.80		100.00	2
1331	1331 PEACH ORCHARD	Distribution	Unattended	230.00	12.00		25.00	1
1332	1332 PEACH ORCHARD	Distribution	Unattended	13.80	12.00		25.00	1
1333	1333 PEACH ORCHARD	Distribution	Unattended	230.00	12.00		22.40	1
1334	1334 PEACHTREE	Distribution	Unattended	230.00	20.00		180.00	3
1335	1335 PEACHTREE	Distribution	Unattended	230.00	20.00		56.00	1
1336	1336 PEACHTREE CITY #2	Distribution	Unattended	115.00	12.00		44.80	2
1337	1337 PEACHTREE CORNERS	Distribution	Unattended	230.00	25.00		56.00	1
1338	1338 PEACHTREE CORNERS	Distribution	Unattended	230.00	25.00		60.00	1
1339	1339 PEARSON	Distribution	Unattended	115.00	12.00		7.00	1
1340	1340 PEEPLES VALLEY	Distribution	Unattended	115.00	25.00		25.00	1
1341	1341 PEEPLES VALLEY	Distribution	Unattended	115.00	25.00		40.00	1
1342	1342 PELHAM	Distribution	Unattended	46.00	12.00		10.50	2

1343	1343 PEMBROKE	Distribution	Unattended	115.00	25.00		25.00	1	
1344	1344 PENN CAMP ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1345	1345 PENN PAK	Distribution	Unattended	46.00	0.48		1.93	1	
1346	1346 PERIMETER CENTER	Distribution	Unattended	230.00	20.00		168.00	3	
1347	1347 PERRY	Transmission	Unattended	115.00	46.00		25.00	1	
1348	1348 PERRY	Transmission	Unattended	115.00	12.00		10.50	1	
1349	1349 PERRY	Transmission	Unattended	115.00	12.00		44.80	2	
1350	1350 PETERSBURG ROAD	Distribution	Unattended	115.00	12.00		10.50	1	
1351	1351 PETERSON CREEK	Distribution	Unattended	115.00	12.00		7.00	1	
1352	1352 PETTIT CREEK	Distribution	Unattended	115.00	46.00		56.00	1	
1353	1353 PETTIT CREEK	Distribution	Unattended	115.00	12.00		33.30	1	
1354	1354 PHARMATECH	Distribution	Unattended	46.00	0.48		4.69	1	
1355	1355 PHARMATECH	Distribution	Unattended	46.00	0.48		3.50	1	
1356	1356 PHILEMA ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1357	1357 PILGRIMS PRIDE #1 (Athens)	Distribution	Unattended	46.00	0.48		1.93	1	
1358	1358 PILGRIMS PRIDE #1 (Athens)	Distribution	Unattended	46.00	0.48		3.50	1	
1359	1359 PILGRIMS PRIDE #2 (Athens)	Distribution	Unattended	46.00	0.48		7.00	1	
1360	1360 PILGRIMS PRIDE #3 (Athens)	Distribution	Unattended	12.00	0.48		2.80	1	
1361	1361 PILGRIMS PRIDE (Canton)	Distribution	Unattended	25.00	0.48		7.00	2	
1362	1362 PILGRIMS PRIDE (Industrial Boulevard)	Distribution	Unattended	46.00	12.00		7.00	1	
1363	1363 PINE GROVE PRIMARY	Transmission	Unattended	115.00	25.00		40.00	1	
1364	1364 PINE MOUNTAIN	Distribution	Unattended	115.00	25.00		44.80	2	
1365	1365 PINSON	Distribution	Unattended	115.00	12.00		22.40	1	
1366	1366 PINSON	Distribution	Unattended	115.00	25.00		44.80	2	
1367	1367 PITTMAN ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1368	1368 PITTS CHAPEL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1369	1369 PLAINS	Distribution	Unattended	46.00	12.00		5.25	1	
1370	1370 PLANTATION PIPELINE PM (Bio)	Distribution	Unattended	46.00	12.00		0.25	1	
1371	1371 PLANTATION PIPELINE (Austell)	Distribution	Unattended	115.00	4.00		11.20	2	
1372	1372 PLANTATION PIPELINE (Bremen)	Distribution	Unattended	115.00	4.00		44.80	2	
1373	1373 PLANTATION PIPELINE (Doraville)	Distribution	Unattended	46.00	4.00		6.25	1	
1374	1374 PLANTATION PIPELINE (Lafayette)	Distribution	Unattended	20.00	2.40		3.00	6	
1375		Distribution	Unattended	115.00	4.00		21.00	2	

	1375 PLANTATION PIPELINE (Neese)							
1376	1376 PLANTATION PIPELINE (Subligna)	Distribution	Unattended	46.00	2.40		2.50	3
1377	1377 PLANTATION ROAD	Distribution	Unattended	115.00	25.00		56.00	1
1378	1378 PLEASANTDALE ROAD	Distribution	Unattended	230.00	25.00		120.00	2
1379	1379 POMONA	Distribution	Unattended	115.00	12.00		22.40	1
1380	1380 PONCE DE LEON	Distribution	Unattended	115.00	25.00		56.00	1
1381	1381 PONCE DE LEON	Distribution	Unattended	115.00	25.00		40.00	1
1382	1382 POOLER	Distribution	Unattended	46.00	13.80		10.50	1
1383	1383 POOLER	Distribution	Unattended	46.00	13.80		28.00	2
1384	1384 PORTERDALE PRIMARY	Distribution	Unattended	115.00	25.00		10.50	1
1385	1385 PORTERDALE PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1
1386	1386 PORTERDALE PRIMARY	Distribution	Unattended	115.00	25.00		40.00	1
1387	1387 PORTERDALE PRIMARY	Distribution	Unattended	46.00	12.00	7	10.50	1
1388	1388 PORTLAND	Transmission	Unattended	115.00	46.00		50.00	1
1389	1389 POTTERVILLE PM	Distribution	Unattended	46.00	12.00		0.25	1
1390	1390 POTTERY OUTLET PD (RETIRED)	Distribution	Unattended	46.00	12.00		2.50	1
1391	1391 POULAN	Distribution	Unattended	46.00	12.00		1.67	2
1392	1392 POULAN	Distribution	Unattended	46.00	12.00		1.25	1
1393	1393 POWDER SPRINGS	Distribution	Unattended	115.00	12.00		33.60	1
1394	1394 POWDER SPRINGS	Distribution	Unattended	115.00	25.00		33.60	1
1395	1395 POWER LINE ROAD	Distribution	Unattended	115.00	13.80		10.50	1
1396	1396 POWER PARTNERS	Distribution	Unattended	46.00	4.00		5.25	1
1397	1397 POWER PARTNERS	Distribution	Unattended	46.00	4.00		3.75	1
1398	1398 POWERS FERRY	Distribution	Unattended	230.00	20.00		240.00	4
1399	1399 PPG INDUSTRIES	Distribution	Unattended	115.00	12.00		10.50	1
1400	1400 PRATT & WHITNEY	Distribution	Unattended	115.00	13.80		44.80	2
1401	1401 PRAYON	Distribution	Unattended	13.80	4.00		2.80	1
1402	1402 PREFERRED COMPOUNDING #2 PM	Distribution	Unattended	46.00	4.00		0.25	1
1403	1403 PREFERRED COMPOUNDING #2 PM	Distribution	Unattended	46.00	4.00		0.56	2
1404	1404 PREFERRED COMPOUNDING #4 PD	Distribution	Unattended	46.00	4.00		2.50	1
1405	1405 PRESIDENT STREET SEWAGE	Distribution	Unattended	46.00	4.00		21.00	2
1406	1406 PRESTON	Distribution	Unattended	46.00	12.00		4.20	1
1407	1407 PRINGLE ROAD	Distribution	Unattended	46.00	12.00		7.00	1

1408	1408 PROCTER & GAMBLE (Albany)	Distribution	Unattended	115.00	13.80		60.00	1	
1409	1409 PROCTER & GAMBLE (Albany)	Distribution	Unattended	115.00	13.80		93.33	2	
1410	1410 PROFILE EXTRUSIONS PD	Distribution	Unattended	46.00	0.48		3.50	1	
1411	1411 PROPEX #1 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1412	1412 PROPEX #1 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.80	1	
1413	1413 PROPEX #10 (Hazlehurst)	Distribution	Unattended	46.00	0.48		7.00	2	
1414	1414 PROPEX #11 (Hazlehurst)	Distribution	Unattended	46.00	0.48		1.68	1	
1415	1415 PROPEX #2 (Hazlehurst)	Distribution	Unattended	46.00	0.48		5.04	3	
1416	1416 PROPEX #3 (Hazlehurst)	Distribution	Unattended	46.00	0.48		5.60	2	
1417	1417 PROPEX #4 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.80	1	
1418	1418 PROPEX #4 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1419	1419 PROPEX #4 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1420	1420 PROPEX #5 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1421	1421 PROPEX #5 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.80	1	
1422	1422 PROPEX #6 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.10	1	
1423	1423 PROPEX #7 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1424	1424 PROPEX #7 (Hazlehurst)	Distribution	Unattended	46.00	0.48		4.20	1	
1425	1425 PROPEX #9 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.80	1	
1426	1426 PUBLIC SAFETY TRAINING CENTER	Distribution	Unattended	115.00	12.00		6.25	1	
1427	1427 PULASKI	Distribution	Unattended	46.00	12.00		3.75	3	
1428	1428 PULASKI SEWAGE PM	Distribution	Unattended	46.00	12.00		0.75	3	
1429	1429 PURCELL ROAD	Distribution	Unattended	230.00	25.00		60.00	1	
1430	1430 PUTNAM PM	Distribution	Unattended	46.00	12.00		0.25	1	
1431	1431 PYRAMAX CERAMICS	Distribution	Unattended	46.00	25.00		10.50	1	
1432	1432 QUACCO ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
1433	1433 QUACCO ROAD	Distribution	Unattended	115.00	13.80		33.30	1	
1434	1434 QUAIL HOLLOW PM	Distribution	Unattended	46.00	12.00		0.25	1	
1435	1435 QUAIL RIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1436	1436 QUALITY PRODUCTS	Distribution	Unattended	46.00	0.48		1.68	1	
1437	1437 QUINTON DILLINGHAM PM	Distribution	Unattended	46.00	12.00		0.25	1	
1438	1438 R. M. MOORE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1439	1439 RADIUM SPRINGS	Distribution	Unattended	115.00	12.00		22.40	1	
1440	1440 RAGLAND STREET	Distribution	Unattended	115.00	12.00		22.40	1	
1441	1441 RAINBOW DRIVE	Distribution	Unattended	115.00	20.00		60.00	1	
1442	1442 RAINBOW DRIVE	Distribution	Unattended	115.00	20.00		40.00	1	
1443		Distribution	Unattended	46.00	0.48		3.50	1	

	1443 RALSTON PURINA MILLS (Gainesville)								
1444	1444 RANDALL	Distribution	Unattended	46.00	12.00		10.50	2	
1445	1445 RAY MOUNTAIN PM	Distribution	Unattended	46.00	12.00		0.25	1	
1446	1446 RAY MOUNTAIN 2 PM	Distribution	Unattended	46.00	12.00		0.33	1	
1447	1447 RAYONIER (Eatonton)	Distribution	Unattended	46.00	12.00		5.25	1	
1448	1448 RAYONIER (Jesup)	Distribution	Unattended	115.00	13.80		33.60	1	
1449	1449 RAYONIER (Jesup)	Distribution	Unattended	115.00	13.80		40.00	1	
1450	1450 REAL DEALS	Distribution	Unattended	46.00	0.60		2.10	1	
1451	1451 REBECCA	Distribution	Unattended	46.00	12.00		1.50	3	
1452	1452 RED DOG FARM ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1453	1453 RED TOP MOUNTAIN	Distribution	Unattended	115.00	46.00		25.00	1	
1454	1454 RED TOP MOUNTAIN	Distribution	Unattended	115.00	12.00		25.00	1	
1455	1455 REDMOND CIRCLE	Distribution	Unattended	115.00	12.00		25.00	1	
1456	1456 REDMOND CIRCLE	Distribution	Unattended	115.00	12.00		22.40	1	
1457	1457 REFUGE ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1458	1458 REIDS	Distribution	Unattended	46.00	12.00		6.25	1	
1459	1459 REIDS PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1460	1460 REIDSVILLE	Distribution	Unattended	115.00	12.00		22.40	1	
1461	1461 REIDSVILLE	Distribution	Unattended	115.00	25.00		10.00	1	
1462	1462 REMERTON	Distribution	Unattended	115.00	12.00		44.80	2	
1463	1463 REMLERS CORNER	Distribution	Unattended	46.00	13.80		25.00	1	
1464	1464 REMLERS CORNER	Distribution	Unattended	46.00	13.80		20.00	1	
1465	1465 REMLERS CORNER	Distribution	Unattended	46.00	13.80		22.40	1	
1466	1466 RENESSENZ	Distribution	Unattended	46.00	12.00		2.50	1	
1467	1467 RENESSENZ	Distribution	Unattended	46.00	12.00		4.20	1	
1468	1468 REST HAVEN	Distribution	Unattended	115.00	25.00		10.50	1	
1469	1469 REST HAVEN	Distribution	Unattended	115.00	25.00		25.00	1	
1470	1470 RETTCO STEEL	Distribution	Unattended	46.00	0.48		7.00	2	
1471	1471 REYNOLDS	Distribution	Unattended	46.00	12.00		5.25	1	
1472	1472 RHINE	Distribution	Unattended	46.00	12.00		7.00	2	
1473	1473 RICE CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
1474	1474 RICHARDSON STREET	Distribution	Unattended	115.00	12.00		22.40	1	
1475	1475 RICHMOND HILL	Distribution	Unattended	115.00	13.80		44.80	2	
1476	1476 RIDGEWAY CHURCH ROAD	Distribution	Unattended	115.00	12.00		120.00	2	
1477	1477 RINGGOLD	Distribution	Unattended	115.00	12.00		22.40	1	
1478	1478 RINGGOLD	Distribution	Unattended	115.00	25.00		25.00	1	
1479	1479 RISING FAWN	Distribution	Unattended	46.00	12.00		4.69	1	

1480	1480 RITE AID (Newnan)	Distribution	Unattended	46.00	0.48		3.50	1	
1481	1481 RIVER ROAD	Distribution	Unattended	25.00	20.00		6.25	1	
1482	1482 RIVER ROAD	Distribution	Unattended	115.00	20.00		40.00	1	
1483	1483 RIVER STREET	Distribution	Unattended	46.00	13.80		120.00	3	
1484	1484 RIVERDALE	Distribution	Unattended	115.00	25.00		56.00	1	
1485	1485 RIVERDALE	Distribution	Unattended	115.00	25.00		40.00	1	
1486	1486 RIVERSIDE MILLS	Distribution	Unattended	46.00	4.00		14.00	2	
1487	1487 RIVERSTONE	Distribution	Unattended	115.00	25.00		40.00	1	
1488	1488 RIVERVIEW HYDRO	Generation	Attended	12.00	2.40		2.00	6	
1489	1489 RIVERWOOD #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1490	1490 RIVERWOOD #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1491	1491 ROBERTS ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
1492	1492 ROBERTS ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
1493	1493 ROBERTS ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
1494	1494 ROBINS AFB #1	Distribution	Unattended	115.00	12.00		89.60	4	
1495	1495 ROBINS AFB #2	Distribution	Unattended	115.00	12.00		25.00	1	
1496	1496 ROBINS AFB #2	Distribution	Unattended	115.00	12.00		44.80	2	
1497	1497 ROBINS AFB #3	Distribution	Unattended	12.00	4.00		7.00	1	
1498	1498 ROBINS AFB #4 - W.D. Fowler	Distribution	Unattended	115.00	12.00		25.00	1	
1499	1499 ROBINS AFB SOLAR	Generation	Attended	115.00	34.50		145.00	1	
1500	1500 ROBINS CT	Generation	Attended	115.00	13.80		220.00	1	
1501	1501 ROCHELLE	Distribution	Unattended	46.00	12.00		7.00	1	
1502	1502 ROCHELLE	Distribution	Unattended	46.00	12.00		7.00	1	
1503	1503 ROCKBRIDGE ROAD	Distribution	Unattended	230.00	12.00		40.00	1	
1504	1504 ROCKMART	Distribution	Unattended	46.00	12.00		15.75	3	
1505	1505 ROCKY FORD ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
1506	1506 ROGERS LANDING PM	Distribution	Unattended	46.00	12.00		0.25	1	
1507	1507 ROME	Distribution	Unattended	115.00	12.00		22.40	1	
1508	1508 ROME	Distribution	Unattended	115.00	12.00		40.00	1	
1509	1509 ROOPVILLE	Distribution	Unattended	230.00	12.00		25.00	1	
1510	1510 ROPER INDUSTRIES	Distribution	Unattended	46.00	0.48		2.80	1	
1511	1511 ROPER INDUSTRIES #2	Distribution	Unattended	46.00	0.48		2.80	1	
1512	1512 ROPERS CORNER	Distribution	Unattended	115.00	12.00		66.66	2	
1513	1513 ROSSIGNOL HILL	Distribution	Unattended	46.00	13.80		22.40	1	
1514	1514 ROSSIGNOL HILL	Distribution	Unattended	46.00	13.80		20.00	1	
1515	1515 ROSSMAN PM	Distribution	Unattended	46.00	12.00		0.25	1	

1516	1516 ROSWELL	Distribution	Unattended	115.00	25.00		60.00	1	
1517	1517 ROSWELL	Distribution	Unattended	115.00	25.00		56.00	1	
1518	1518 ROTTENWOOD CREEK	Distribution	Unattended	115.00	20.00		120.00	2	
1519	1519 ROYAL ATLANTA	Distribution	Unattended	230.00	25.00		60.00	1	
1520	1520 ROYSTON	Distribution	Unattended	46.00	12.00		6.25	1	
1521	1521 ROYSTON	Distribution	Unattended	46.00	12.00		6.25	1	
1522	1522 ROYSTON MANUFACTURING	Distribution	Unattended	46.00	0.48		2.10	1	
1523	1523 RUCKER BROTHERS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1524	1524 RUSSELL AREA PM Retired	Distribution	Unattended	46.00	12.00		0.25	1	
1525	1525 SAGE AUTOMOTIVE INTERIORS	Distribution	Unattended	115.00	0.60		14.00	2	
1526	1526 SAINT MARYS	Distribution	Unattended	115.00	12.00		22.40	1	
1527	1527 SAINT MARYS ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
1528	1528 SAINT MARYS ROAD	Distribution	Unattended	115.00	46.00		60.00	1	
1529	1529 SAINT SIMONS	Distribution	Unattended	115.00	12.00		44.80	2	
1530	1530 SALE CITY	Distribution	Unattended	46.00	12.00		5.25	1	
1531	1531 SALEM GATE	Distribution	Unattended	115.00	12.00		33.60	1	
1532	1532 SANDERSON FARMS	Distribution	Unattended	46.00	25.00		10.00	1	
1533	1533 SANDERSVILLE CLAY	Distribution	Unattended	46.00	0.48		2.50	3	
1534	1534 SANDY BOTTOM	Distribution	Unattended	115.00	12.00		10.50	1	
1535	1535 SANDY SPRINGS	Distribution	Unattended	230.00	20.00		56.00	1	
1536	1536 SAPA EXTRUDER	Distribution	Unattended	46.00	0.48		4.69	1	
1537	1537 SAPA EXTRUDER	Distribution	Unattended	46.00	0.48		3.50	1	
1538	1538 SARDIS	Distribution	Unattended	115.00	12.00		21.00	2	
1539	1539 SARGENT	Distribution	Unattended	46.00	12.00		14.00	2	
1540	1540 SASSER	Distribution	Unattended	46.00	12.00		2.00	3	
1541	1541 SATILLA CREEK	Distribution	Unattended	115.00	12.00		7.00	1	
1542	1542 SAULTER PM	Distribution	Unattended	46.00	12.00		0.25	1	
1543	1543 SAVANNAH FOODS	Distribution	Unattended	46.00	4.00		10.50	1	
1544	1544 SCHERER CONSTRUCTION	Distribution	Attended	115.00	12.00		21.00	2	
1545	1545 SCHERER FGD 1/2	Generation	Attended	115.00	13.80		300.00	4	
1546	1546 SCHERER FGD 3/4	Generation	Attended	115.00	13.80		300.00	4	
1547	1547 SCHERER FGD 3/4	Generation	Attended	115.00	4.00		25.00	1	
1548	1548 SCHERER FGD 3/4	Generation	Attended	115.00	12.00		25.00	1	
1549	1549 SCHERER RIVER PUMPING	Distribution	Attended	115.00	4.00		11.20	2	
1550	1550 SCHERER UNIT 1	Generation	Attended	500.00	25.00		327.00	1	
1551	1551 SCHERER UNIT 1	Generation	Attended	500.00	25.00		584.00	2	

1552	1552 SCHERER UNIT 1	Generation	Attended	25.00	4.16		224.00	4	
1553	1553 SCHERER UNIT 2	Generation	Attended	500.00	25.00		876.00	3	
1554	1554 SCHERER UNIT 2	Generation	Attended	25.00	4.16		224.00	4	
1555	1555 SCHERER UNIT 3	Generation	Attended	25.00	4.16	4	56.00	1	
1556	1556 SCHERER UNIT 3	Generation	Attended	25.00	4.16	7	56.00	1	
1557	1557 SCHERER UNIT 3	Generation	Attended	500.00	25.00		876.00	3	
1558	1558 SCHERER UNIT 4	Generation	Attended	500.00	25.00		981.00	3	
1559	1559 SCHERER UNIT 4	Generation	Attended	25.00	4.16		33.60	1	
1560	1560 SCHERER UNIT 4	Generation	Attended	25.00	4.16		112.00	2	
1561	1561 SCOTT HUDGENS BUILDING	Distribution	Unattended	20.00	0.48		1.12	1	
1562	1562 SCOTTDALE	Distribution	Unattended	115.00	20.00		60.00	1	
1563	1563 SCOTTDALE	Distribution	Unattended	115.00	20.00		56.00	1	
1564	1564 SCOVILLE MANUFACTURING	Distribution	Unattended	46.00	0.48		4.48	2	
1565	1565 SCOVILLE MANUFACTURING	Distribution	Unattended	46.00	0.48		2.15	1	
1566	1566 SEA ISLAND	Distribution	Unattended	115.00	12.00		22.40	1	
1567	1567 SEALY PM	Distribution	Unattended	46.00	12.00		0.25	1	
1568	1568 SEARS FASHION CENTER 25/4 KV	Distribution	Unattended	25.00	4.00		2.80	1	
1569	1569 SEVENTH AVENUE	Distribution	Unattended	115.00	12.00		22.40	1	
1570	1570 SEVENTH AVENUE	Distribution	Unattended	115.00	25.00		80.00	2	
1571	1571 SEWELL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1572	1572 SHARON PD	Distribution	Unattended	46.00	12.00		2.50	1	
1573	1573 SHAW INDUSTRIES #2 PD (Trenton)	Distribution	Unattended	46.00			5.00	1	
1574	1574 SHAW INDUSTRIES (Milledgeville)	Distribution	Unattended	12.00	0.48		3.50	1	
1575	1575 SHAW INDUSTRIES (Milledgeville)	Distribution	Unattended	12.00	0.48		2.80	1	
1576	1576 SHAW INDUSTRIES (Thomson)	Distribution	Unattended	115.00	4.00		37.50	4	
1577	1577 SHAW INDUSTRIES (Thomson)	Distribution	Unattended	115.00	4.00		22.40	1	
1578	1578 SHENANDOAH SEWAGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1579	1579 SHENANDOAH SEWAGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1580	1580 SHILOH	Distribution	Unattended	115.00	25.00		21.00	2	
1581	1581 SHURLING DRIVE	Distribution	Unattended	115.00	12.00		40.00	2	
1582	1582 SHURLING DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
1583	1583 SILGAN PLASTICS	Distribution	Unattended	46.00	4.00		5.00	1	
1584	1584 SILK HOPE	Distribution	Unattended	46.00	13.80		25.00	1	
1585	1585 SIMPSON LUMBER	Distribution	Unattended	46.00	13.80		7.00	1	
1586	1586 SINCLAIR DAM HYDRO	Generation	Attended	6.60	0.60		1.00	2	

1587	1587 SINCLAIR DAM HYDRO	Generation	Attended	115.00	6.60		50.00	2	
1588	1588 SIX MILE	Distribution	Unattended	115.00	25.00		44.80	2	
1589	1589 SIX MILE	Distribution	Unattended	115.00	12.00		10.50	1	
1590	1590 SKIDAWAY ISLAND	Distribution	Unattended	115.00	25.00		25.00	1	
1591	1591 SKIDAWAY ISLAND	Distribution	Unattended	115.00	25.00		67.20	2	
1592	1592 SLAPPEY DRIVE	Distribution	Unattended	115.00	12.00		44.80	2	
1593	1593 SMITHVILLE	Distribution	Unattended	115.00	25.00		10.50	1	
1594	1594 SMITHVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
1595	1595 SMITHVILLE	Distribution	Unattended	115.00	46.00		25.00	1	
1596	1596 SMYRNA	Distribution	Unattended	115.00	20.00		50.00	1	
1597	1597 SMYRNA	Distribution	Unattended	115.00	20.00		50.00	1	
1598	1598 SNAPFINGER ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
1599	1599 SOCIAL CIRCLE	Distribution	Unattended	46.00	12.00		7.00	1	
1600	1600 SOCIAL CIRCLE	Distribution	Unattended	46.00	12.00		5.25	1	
1601	1601 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	46.00	12.00		5.00	1	
1602	1602 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	115.00	25.00		10.00	1	
1603	1603 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	115.00	46.00		22.40	1	
1604	1604 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	46.00	12.00		7.00	1	
1605	1605 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1606	1606 SOLO CUP #1	Distribution	Unattended	46.00	0.48		7.00	1	
1607	1607 SOLO CUP #1	Distribution	Unattended	46.00	0.48		3.50	1	
1608	1608 SOLO CUP #1	Distribution	Unattended	46.00	0.48		5.25	1	
1609	1609 SOLVAY ADVANCED POLYMERS	Distribution	Unattended	115.00	13.80		80.00	2	
1610	1610 SOPERTON PRIMARY	Distribution	Unattended	115.00	12.00		10.50	1	
1611	1611 SOUTH ADEL	Distribution	Unattended	115.00	12.00		25.00	1	
1612	1612 SOUTH ADEL	Distribution	Unattended	115.00	12.00		22.40	1	
1613	1613 SOUTH ATHENS	Distribution	Unattended	115.00	12.00		33.60	1	
1614	1614 SOUTH AUGUSTA	Transmission	Unattended	115.00	13.80		33.60	1	
1615	1615 SOUTH AUGUSTA	Transmission	Unattended	115.00	13.80		25.00	1	
1616	1616 SOUTH CHATTOOGA	Transmission	Unattended	115.00	46.00		25.00	1	
1617	1617 SOUTH CHATTOOGA	Transmission	Unattended	46.00	12.00		7.00	1	
1618	1618 SOUTH CLEVELAND	Distribution	Unattended	115.00	25.00		10.50	1	
1619	1619 SOUTH COBB DRIVE	Distribution	Unattended	115.00	20.00		80.00	2	
1620	1620 SOUTH COLUMBUS	Distribution	Unattended	115.00	12.00		25.00	1	

1621	1621 SOUTH DAHLONEGA	Distribution	Unattended	115.00	25.00		25.00	1	
1622	1622 SOUTH EFFINGHAM	Distribution	Unattended	115.00	13.80		33.60	1	
1623	1623 SOUTH GAINESVILLE	Distribution	Unattended	46.00	12.00		12.07	1	
1624	1624 SOUTH GAINESVILLE	Distribution	Unattended	115.00	46.00		50.00	1	
1625	1625 SOUTH GAINESVILLE	Distribution	Unattended	46.00	12.00		12.09	1	
1626	1626 SOUTH GEORGETOWN PM	Distribution	Unattended	46.00	12.00		0.25	1	
1627	1627 SOUTH GEORGIA METHODIST NURSING HOME	Distribution	Unattended	46.00	0.48		3.36	6	
1628	1628 SOUTH MACON	Distribution	Unattended	115.00	12.00		22.40	1	
1629	1629 SOUTH MACON	Distribution	Unattended	115.00	12.00		25.00	1	
1630	1630 SOUTH MADISON	Distribution	Unattended	46.00	12.00		15.75	3	
1631	1631 SOUTH MADISON	Distribution	Unattended	115.00	12.00		20.00	1	
1632	1632 SOUTH MADISON	Distribution	Unattended	115.00	25.00		44.80	2	
1633	1633 SOUTH MCRAE	Distribution	Unattended	46.00	12.00		10.50	2	
1634	1634 SOUTH NORCROSS	Distribution	Unattended	115.00	25.00		40.00	1	
1635	1635 SOUTH NORCROSS	Distribution	Unattended	115.00	25.00		22.40	1	
1636	1636 SOUTH NORCROSS	Distribution	Unattended	115.00	46.00		25.00	1	
1637	1637 SOUTH OGLETHORPE	Distribution	Unattended	115.00	12.00		10.50	1	
1638	1638 SOUTH OGLETHORPE	Distribution	Unattended	115.00	46.00		50.00	1	
1639	1639 SOUTH RIVER WASTEWATER TREATMENT	Distribution	Unattended	20.00	12.00		21.00	2	
1640	1640 SOUTH TIFTON	Distribution	Unattended	115.00	12.00		21.00	2	
1641	1641 SOUTH VILLA RICA	Distribution	Unattended	115.00	25.00		40.00	1	
1642	1642 SOUTH VILLA RICA	Distribution	Unattended	115.00	25.00		40.00	1	
1643	1643 SOUTHEAST TOYOTA	Distribution	Unattended	115.00	12.00		7.00	1	
1644	1644 SOUTHEAST WAYCROSS	Distribution	Unattended	115.00	12.00		25.00	1	
1645	1645 SOUTHEAST WAYCROSS	Distribution	Unattended	115.00	12.00		22.40	1	
1646	1646 SOUTHEASTERN ASSEMBLY	Distribution	Unattended	46.00	0.48		3.36	2	
1647	1647 SOUTHEASTERN REG RES LAB	Distribution	Unattended	12.00	0.48		7.00	2	
1648	1648 SOUTHERN BELL	Distribution	Unattended	13.20	0.48		3.00	2	
1649	1649 SOUTHERN LNG	Distribution	Unattended	115.00	13.80		80.00	2	
1650	1650 SOUTHERN LNG	Distribution	Unattended	115.00	34.50		480.00	4	
1651	1651 SOUTHERN MILLS #1 (Senoia)	Distribution	Unattended	46.00	0.60		2.50	3	
1652	1652 SOUTHERN MILLS #2 (Senoia)	Distribution	Unattended	46.00	0.60		3.50	1	
1653	1653 SOUTHERN MILLS (Zebulon)	Distribution	Unattended	46.00	0.60		2.80	1	
1654	1654 SOUTHERN NATURAL GAS (Ellerslie)	Distribution	Unattended	230.00	4.00		25.00	1	

1655	1655 SOUTHERN NATURAL GAS (Ellerslie)	Distribution	Unattended	230.00	4.00			1	
1656	1656 SOUTHERN NATURAL GAS (Fairburn)	Distribution	Unattended	115.00	13.80		25.00	1	
1657	1657 SOUTHERN RAILWAY	Distribution	Unattended	12.00	2.40		2.80	3	
1658	1658 SOUTHERN RAILWAY (Inman Yards)	Distribution	Unattended	20.00	2.40		7.00	2	
1659	1659 SOUTHERN STATES CO-OP	Distribution	Unattended	46.00	0.48		1.68	1	
1660	1660 SOUTHERN WOOD SUPPLIES	Distribution	Unattended	46.00	0.60		7.00	1	
1661	1661 SOUTHERN WOOD SUPPLIES	Distribution	Unattended	46.00	4.00		5.25	1	
1662	1662 SOUTHWEST DUBLIN	Distribution	Unattended	115.00	12.00		33.60	1	
1663	1663 SOUTHWIRE	Distribution	Unattended	115.00	12.00		44.80	2	
1664	1664 SOUTHWIRE #2	Distribution	Unattended	115.00	12.00		25.00	1	
1665	1665 SPALDING	Distribution	Unattended	115.00	46.00		22.40	1	
1666	1666 SPALDING	Distribution	Unattended	115.00	12.00		7.00	1	
1667	1667 SPALDING DRIVE	Distribution	Unattended	115.00	25.00		56.00	1	
1668	1668 SPALDING DRIVE	Distribution	Unattended	115.00	20.00		56.00	1	
1669	1669 SPARTA #2	Distribution	Unattended	46.00	12.00		7.00	1	
1670	1670 SPECIALTY YARN AND CONVERTING	Distribution	Unattended	25.00	0.60		3.50	1	
1671	1671 SPIRIT CREEK	Distribution	Unattended	115.00	13.80		22.40	1	
1672	1672 SPIVEY LAKE	Distribution	Unattended	115.00	25.00		60.00	1	
1673	1673 SPRING STREET	Distribution	Unattended	115.00	20.00		120.00	2	
1674	1674 SPRING STREET	Distribution	Unattended	115.00	20.00		50.00	1	
1675	1675 SPRING STREET	Distribution	Unattended	115.00	20.00		56.00	1	
1676	1676 SPRINGFIELD	Distribution	Unattended	115.00	25.00		40.00	1	
1677	1677 STANDRIDGE COLOR #1	Distribution	Unattended	46.00	0.48		2.80	1	
1678	1678 STANDRIDGE COLOR #1	Distribution	Unattended	46.00	0.48		7.00	2	
1679	1679 STANDRIDGE COLOR #18 PM	Distribution	Unattended	46.00	12.00		0.75	3	
1680	1680 STANDRIDGE COLOR #2	Distribution	Unattended	46.00	0.48		3.50	1	
1681	1681 STANTON SPRINGS	Distribution	Unattended	115.00	13.80		25.00	1	
1682	1682 STATE HIGHWAY TESTING LAB	Distribution	Unattended	25.00	0.48		3.50	1	
1683	1683 STATENVILLE PD	Distribution	Unattended	46.00	12.00		5.00	1	
1684	1684 STATESBORO	Distribution	Unattended	115.00	12.00		22.40	1	
1685	1685 STATESBORO	Distribution	Unattended	115.00	12.00		25.00	1	
1686	1686 STATESBORO AREA #4 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1687	1687 STATESBORO AREA #8 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1688	1688 STATESBORO PRIMARY	Distribution	Unattended	115.00	25.00		27.48	1	

1689	1689 STATESBORO PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1690	1690 STATHAM	Distribution	Unattended	115.00	25.00		25.00	1	
1691	1691 STEEPLECHASE PM	Distribution	Unattended	46.00	12.00		0.33	1	
1692	1692 STEVENS CREEK	Transmission	Unattended	115.00	13.80		25.00	1	
1693	1693 STEVENS CREEK	Transmission	Unattended	115.00	46.00		25.00	1	
1694	1694 STILESBORO	Distribution	Unattended	46.00	12.00		10.50	2	
1695	1695 STOCKBRIDGE	Transmission	Unattended	115.00	25.00		60.00	1	
1696	1696 STOCKBRIDGE	Transmission	Unattended	115.00	25.00		40.00	1	
1697	1697 STOKES LAKE PD	Distribution	Unattended	46.00	25.00		5.00	1	
1698	1698 STONE MOUNTAIN	Distribution	Unattended	115.00	25.00		60.00	1	
1699	1699 STONEWALL STREET	Distribution	Unattended	115.00	12.00		50.00	2	
1700	1700 STONEY BROOK PM	Distribution	Unattended	46.00	12.00		0.25	1	
1701	1701 STOWE WOODWARD	Distribution	Unattended	46.00	0.48		3.50	1	
1702	1702 STUBBS ROAD PM	Distribution	Unattended	46.00	7.20			1	
1703	1703 SUMMERVILLE PRIMARY	Distribution	Unattended	115.00	12.00		9.38	1	
1704	1704 SUMMERVILLE PRIMARY	Distribution	Unattended	115.00	12.00		12.32	1	
1705	1705 SUMMERVILLE PRIMARY	Distribution	Unattended	115.00	46.00		40.00	1	
1706	1706 SUMNER	Distribution	Unattended	46.00	12.00		5.60	1	
1707	1707 SUNDANCE PRODUCTS	Distribution	Unattended	46.00	0.48		6.25	1	
1708	1708 SUNSHINE BISCUIT (Columbus)	Distribution	Unattended	12.00	0.48		2.80	1	
1709	1709 SUNSHINE BISCUIT (Columbus)	Distribution	Unattended	12.00	0.48		1.68	1	
1710	1710 SUPER SOD FARM PM	Distribution	Unattended	46.00	12.00		0.75	3	
1711	1711 SUTTONS CROSSROAD	Distribution	Unattended	46.00	12.00		5.25	1	
1712	1712 SUWANEE	Transmission	Unattended	115.00	25.00		60.00	1	
1713	1713 SUWANEE	Transmission	Unattended	115.00	25.00		56.00	1	
1714	1714 SWAINSBORO AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1715	1715 SWAINSBORO AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1716	1716 SWAINSBORO AREA #5 PM	Distribution	Unattended	46.00	12.00		0.28	1	
1717	1717 SWAINSBORO PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1718	1718 SWAINSBORO PRIMARY	Distribution	Unattended	115.00	12.00		22.40	1	
1719	1719 SWEET CITY PD	Distribution	Unattended	46.00	12.00		5.00	1	
1720	1720 SWEETBOTTOM	Distribution	Unattended	230.00	25.00		56.00	1	
1721	1721 SWEETBOTTOM	Distribution	Unattended	230.00	25.00		60.00	1	
1722	1722 SWEETWATER PAPER BOARD	Distribution	Unattended	46.00	0.60		21.00	3	

1723	1723 SWIFT SPINNING MILLS	Distribution	Unattended	12.00	4.00		7.00	1	
1724	1724 SWIFT SPINNING MILLS	Distribution	Unattended	12.00	2.40		14.00	2	
1725	1725 SWIFT SPINNING MILLS #2	Distribution	Unattended	115.00	25.00		25.00	1	
1726	1726 SYLVESTER PRIMARY	Transmission	Unattended	115.00	46.00		22.40	1	
1727	1727 SYLVESTER PRIMARY	Transmission	Unattended	115.00	46.00		29.56	1	
1728	1728 TALLAPOOSA	Distribution	Unattended	115.00	46.00		25.00	1	
1729	1729 TALLAPOOSA	Distribution	Unattended	115.00	12.00		25.00	1	
1730	1730 TALLASSEE ROAD SCHOOL PD	Distribution	Unattended	46.00	12.00		2.50	1	
1731	1731 TALLULAH FALLS	Generation	Attended	115.00	6.60		16.00	1	
1732	1732 TALLULAH FALLS	Generation	Attended	115.00	6.60		12.00	1	
1733	1733 TALLULAH FALLS	Generation	Attended	115.00	6.60		16.00	1	
1734	1734 TALLULAH FALLS	Generation	Attended	115.00	6.60		17.92	1	
1735	1735 TALLULAH FALLS	Generation	Attended	115.00	6.60		35.84	2	
1736	1736 TALMO TAP PD	Distribution	Unattended	46.00	12.00			1	
1737	1737 TALONA PM	Distribution	Unattended	46.00	12.00		0.25	1	
1738	1738 TANNER PM	Distribution	Unattended	46.00	12.00		0.75	3	
1739	1739 TANYARD CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
1740	1740 TARA	Distribution	Unattended	115.00	25.00		56.00	1	
1741	1741 TARVER	Transmission	Unattended	115.00	46.00		25.00	1	
1742	1742 TATUM ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1743	1743 TAYLORSVILLE	Distribution	Unattended	46.00	12.00		14.00	2	
1744	1744 TAZEWELL	Transmission	Unattended	230.00	46.00		40.00	1	
1745	1745 TEMPERANCE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1746	1746 TEMPLE	Distribution	Unattended	115.00	12.00		21.00	2	
1747	1747 TEMPLE INDUSTRIES (Thomson)	Distribution	Unattended	46.00	12.00		7.00	1	
1748	1748 TEMPLE INDUSTRIES (Thomson)	Distribution	Unattended	46.00	12.00		4.20	1	
1749	1749 TENNECO AUTOMOTIVE	Distribution	Unattended	115.00	12.00		22.40	1	
1750	1750 TENNILLE CITY	Distribution	Unattended	46.00	12.00		14.00	2	
1751	1751 TERRORA	Distribution	Unattended	46.00	12.00	7	10.50	1	
1752	1752 TERRORA HYDRO	Generation	Attended	115.00	46.00		44.80	2	
1753	1753 TERRORA HYDRO	Generation	Attended	115.00	6.60		30.00	1	
1754	1754 TEXAS VALLEY	Distribution	Unattended	115.00	12.00		5.25	1	
1755	1755 TEXTRON SPECIALITY PRODUCTS	Distribution	Unattended	115.00	13.80		22.40	1	
1756	1756 THALMANN STATION SERVICE	Distribution	Unattended	115.00	12.00		9.37	2	
1757	1757 THE BRIDGE CHURCH	Distribution	Unattended	25.00	0.48		2.10	1	

1758	1758 THE ROCK	Distribution	Unattended	25.00	0.48		12.50	4	
1759	1759 THE ROCK	Distribution	Unattended	230.00	25.00		22.40	1	
1760	1760 THIELE KAOLIN (Limestone Creek)	Distribution	Unattended	46.00	12.00		7.00	1	
1761	1761 THIELE KAOLIN (Mine)	Distribution	Unattended	46.00	12.00		5.25	1	
1762	1762 THIELE KAOLIN (Sandersville)	Distribution	Unattended	46.00	12.00		14.00	2	
1763	1763 THIELE KAOLIN (Sandersville)	Distribution	Unattended	46.00	12.00		7.00	1	
1764	1764 THIELE KAOLIN (Wrens)	Distribution	Unattended	46.00	4.00		6.25	1	
1765	1765 THIELE KAOLIN (Wrens)	Distribution	Unattended	46.00	4.00		14.00	2	
1766	1766 THOMASTON	Distribution	Unattended	115.00	12.00		40.00	1	
1767	1767 THOMASTON	Distribution	Unattended	115.00	25.00		10.50	1	
1768	1768 THOMASTON	Distribution	Unattended	115.00	12.00		22.40	1	
1769	1769 THOMPSON BRIDGE	Distribution	Unattended	115.00	25.00		50.00	2	
1770	1770 THOMSON AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1771	1771 THOMSON AREA #8 PD	Distribution	Unattended	46.00	12.00		2.50	1	
1772	1772 THOMSON PRIMARY	Transmission	Unattended	13.80	0.48		1.00	1	
1773	1773 THOMSON PRIMARY	Transmission	Unattended	115.00	46.00		50.00	2	
1774	1774 THOMSON PRIMARY	Transmission	Unattended	46.00	0.48		2.50	1	
1775	1775 THRALL CAR MANUFACTURING	Distribution	Unattended	25.00	12.00		7.00	1	
1776	1776 THREE RIVERS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1777	1777 TIFTON PRIMARY	Distribution	Unattended	115.00	12.00		67.20	3	
1778	1778 TILLY MILL	Distribution	Unattended	230.00	25.00		60.00	1	
1779	1779 TIMBERMEN #1 (Warrenton)	Distribution	Unattended	46.00	0.48		1.68	1	
1780	1780 TIMBERMEN (Camak)	Distribution	Unattended	46.00	0.48		2.80	1	
1781	1781 TIN BRIDGE PD	Distribution	Unattended	46.00	12.00		2.50	1	
1782	1782 TIOGA	Transmission	Unattended	230.00	46.00		60.00	1	
1783	1783 TNS MILLS	Distribution	Unattended	115.00	25.00		31.50	3	
1784	1784 TOCCOA	Distribution	Unattended	115.00	12.00		25.00	1	
1785	1785 TODD MARSHALL PM	Distribution	Unattended	46.00	12.00		0.25	1	
1786	1786 TOLLESON LUMBER (Perry)	Distribution	Unattended	46.00	0.48		5.60	3	
1787	1787 TOM HUSTON PEANUT (Bakery)	Distribution	Unattended	12.00	0.48		3.50	1	
1788	1788 TOMMY FIELDS PM	Distribution	Unattended	46.00	12.00		0.28	1	
1789	1789 TOTAL SYSTEM SERVICES	Distribution	Unattended	115.00	25.00		10.50	1	
1790	1790 TOTO	Distribution	Unattended	25.00	4.00		7.00	1	
1791	1791 TOWNSEND	Distribution	Unattended	115.00	12.00		5.25	1	

1792	1792 TOYO	Distribution	Unattended	115.00	12.00		80.00	2	
1793	1793 TRANSCO	Distribution	Unattended	115.00	25.00		60.00	1	
1794	1794 TRANSCO	Distribution	Unattended	115.00	12.00		25.00	1	
1795	1795 TRENCH SHORING SERVICES	Distribution	Unattended	46.00	0.48		2.80	1	
1796	1796 TRENT TUBE	Distribution	Unattended	46.00	0.48		3.50	1	
1797	1797 TRENTON	Distribution	Unattended	46.00	12.00		7.00	1	
1798	1798 TRENTON	Distribution	Unattended	46.00	25.00		21.00	3	
1799	1799 TRENTON	Distribution	Unattended	46.00	12.00		5.00	1	
1800	1800 TRENTON	Distribution	Unattended	46.00	12.00		6.25	1	
1801	1801 TREUTLEN	Distribution	Unattended	115.00	25.00		100.00	2	
1802	1802 TRI COUNTY FARMS PM	Distribution	Unattended	46.00	12.00		0.75	3	
1803	1803 TRIBUTARY	Transmission	Unattended	230.00	20.00		60.00	1	
1804	1804 TRINITY INDUSTRIES	Distribution	Unattended	46.00	0.48		2.50	3	
1805	1805 TRION	Distribution	Unattended	115.00	12.00		25.00	1	
1806	1806 TRION	Distribution	Unattended	115.00	12.00		21.00	2	
1807	1807 TRIPPS BEACH PM	Distribution	Unattended	46.00	12.00		0.28	1	
1808	1808 TRONOX	Distribution	Unattended	115.00	13.80		33.60	1	
1809	1809 TROUP CREEK	Distribution	Unattended	115.00	12.00		25.00	1	
1810	1810 TROUP CREEK	Distribution	Unattended	115.00	12.00		67.20	2	
1811	1811 TROY ALDRIDGE PM	Distribution	Unattended	46.00	0.48		0.15	1	
1812	1812 TRUMAN PARKWAY	Distribution	Unattended	115.00	13.80		33.60	1	
1813	1813 TRUMAN PARKWAY	Distribution	Unattended	115.00	13.80		33.60	1	
1814	1814 TUCKER	Distribution	Unattended	115.00	12.00		25.00	1	
1815	1815 TUCKER	Distribution	Unattended	115.00	12.00		40.00	1	
1816	1816 TUGALO	Generation	Attended	115.00	6.60		40.00	1	
1817	1817 TURPIN HILL	Distribution	Unattended	115.00	13.80		33.60	1	
1818	1818 TURPIN HILL	Distribution	Unattended	115.00	13.80		20.00	1	
1819	1819 TWILIGHT	Distribution	Unattended	115.00	25.00		56.00	1	
1820	1820 TWIN CITY	Distribution	Unattended	115.00	12.00		10.50	1	
1821	1821 TWIN LAKES	Transmission	Unattended	115.00	69.00	13	60.00	1	
1822	1822 TWIN LAKES	Transmission	Unattended	115.00	69.00		60.00	1	
1823	1823 TWIN PINES	Distribution	Unattended	115.00	12.00		44.80	2	
1824	1824 TY TY PD	Distribution	Unattended	46.00	12.00		5.00	1	
1825	1825 TYBEE ISLAND	Distribution	Unattended	46.00	13.80		25.00	1	
1826	1826 TYBEE ISLAND	Distribution	Unattended	46.00	13.80		25.00	1	
1827	1827 TYCO PLASTICS #1	Distribution	Unattended	46.00	0.48		2.80	1	
1828	1828 TYCO PLASTICS #11 PD	Distribution	Unattended	46.00			2.50	1	

1829	1829 TYCO PLASTICS #4	Distribution	Unattended	46.00	0.48		3.50	1	
1830	1830 TYCO PLASTICS #8	Distribution	Unattended	46.00	0.48		7.00	2	
1831	1831 TYSON FOODS (Cumming)	Distribution	Unattended	12.00	0.48		3.50	1	
1832	1832 TYSON FOODS (Cumming)	Distribution	Unattended	12.00	0.48		6.25	1	
1833	1833 TYSON FOODS (Gober)	Distribution	Unattended	46.00	0.48		1.29	1	
1834	1834 U.S. CAN (Tallapoosa)	Distribution	Unattended	46.00	0.48		3.50	1	
1835	1835 U.S. MARINE CORPS (MOCK ROAD)	Distribution	Unattended	115.00	34.50		40.00	1	
1836	1836 U.S. MARINE CORPS SUPPLY DEPOT	Distribution	Unattended	34.50	12.00		25.00	1	
1837	1837 U.S. MARINE CORPS SUPPLY DEPOT	Distribution	Unattended	115.00	12.00		22.40	1	
1838	1838 U.S. POSTAL FACILITY (Hapeville)	Distribution	Unattended	20.00	4.00		5.00	1	
1839	1839 U.S. POSTAL SERVICE	Distribution	Unattended	115.00	12.00		14.00	2	
1840	1840 U.S. VETERANS HOSPITAL (Dublin)	Distribution	Unattended	46.00	4.00		14.00	2	
1841	1841 U.S. VETERANS HOSPITAL (Dublin)	Distribution	Unattended	12.00	4.00		5.00	1	
1842	1842 UNILEVER	Distribution	Unattended	20.00	4.00		4.69	1	
1843	1843 UNIMIN	Distribution	Unattended	46.00	12.00		5.25	1	
1844	1844 UNION POINT AREA #1 PM (RETIRED)	Distribution	Unattended	46.00	12.00		0.25	1	
1845	1845 UNION POINT PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1846	1846 UNION POINT PRIMARY	Transmission	Unattended	115.00	25.00		10.50	1	
1847	1847 UNITED PARCEL SERVICE	Distribution	Unattended	115.00	20.00		50.00	2	
1848	1848 UNIVERSITY CENTER	Distribution	Unattended	115.00	20.00		60.00	1	
1849	1849 UNIVERSITY OF GEORGIA	Distribution	Unattended	115.00	12.00		80.00	2	
1850	1850 UNIVERSITY OF GEORGIA	Distribution	Unattended	115.00	12.00		25.00	1	
1851	1851 UNIVERSITY OF WEST GEORGIA	Distribution	Unattended	46.00	12.00		10.00	1	
1852	1852 UPS DATA CENTER (Alpharetta)	Distribution	Unattended	25.00	12.00		44.80	2	
1853	1853 US 1 RECYCLING	Distribution	Unattended	46.00	4.00		4.69	1	
1854	1854 UVALDA	Distribution	Unattended	46.00	12.00		5.25	1	
1855	1855 VALDOSTA	Distribution	Unattended	115.00	12.00		40.00	1	
1856	1856 VALLEY HILL ROAD	Distribution	Unattended	115.00	25.00		56.00	1	
1857	1857 VARNELL	Distribution	Unattended	115.00	12.00		7.00	1	
1858	1858 VARNELL	Distribution	Unattended	115.00	12.00		6.25	1	
1859	1859 VENUS THREAD	Distribution	Unattended	46.00	0.60		5.75	3	
1860	1860 VERDERY STREET	Distribution	Unattended	115.00	13.80		33.60	1	

1861	1861 VICTORY DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
1862	1862 VICTORY DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
1863	1863 VIDALIA	Distribution	Unattended	115.00	12.00		44.80	2	
1864	1864 VIDALIA	Distribution	Unattended	115.00	46.00		56.00	1	
1865	1865 VIENNA PRIMARY	Transmission	Unattended	115.00	46.00		22.40	1	
1866	1866 VIENNA PRIMARY	Transmission	Unattended	115.00	46.00		50.00	1	
1867	1867 VIENNA PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
1868	1868 VILLA RICA PRIMARY	Transmission	Unattended	46.00	0.48		2.50	1	
1869	1869 VILLA RICA PRIMARY	Transmission	Unattended	230.00	46.00		46.67	1	
1870	1870 VINEVILLE	Distribution	Unattended	115.00	12.00		67.20	3	
1871	1871 VINSON ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1872	1872 VIRGINIA AVENUE	Distribution	Unattended	230.00	20.00		120.00	2	
1873	1873 VISY PAPER	Distribution	Unattended	115.00	13.80		25.00	1	
1874	1874 VOGTLE 1&2	Generation	Attended	25.00	1.00		17.14	2	
1875	1875 VOGTLE 1&2	Generation	Attended	500.00	25.00		1356.00	3	
1876	1876 VOGTLE 1&2	Generation	Attended	230.00	25.00		1864.00	4	
1877	1877 VOGTLE 1&2	Generation	Attended	25.00	13.80		336.00	6	
1878	1878 VOGTLE 1&2	Generation	Attended	13.80	4.00		12.50	1	
1879	1879 VOGTLE 1&2	Generation	Attended	230.00	13.80		134.40	2	
1880	1880 VOGTLE 230KV SWITCHING	Transmission	Unattended	230.00	13.80		25.00	1	
1881	1881 VOGTLE 3&4 500KV	Generation	Attended	25.00	1.00		20.00	2	
1882	1882 VOGTLE 3&4 500KV	Generation	Attended	230.00	25.00		1840.00	4	
1883	1883 VOGTLE 3&4 500KV	Generation	Attended	500.00	25.00		1840.00	4	
1884	1884 VULCAN MATERIALS (Columbus)	Distribution	Unattended	25.00	2.40		4.20	1	
1885	1885 VULCAN MATERIALS (Grayson)	Distribution	Unattended	115.00	12.00		14.00	2	
1886	1886 VULCAN MATERIALS (Lithia Springs)	Distribution	Unattended	46.00	2.40		14.00	2	
1887	1887 VULCAN MATERIALS (Lithonia)	Distribution	Unattended	46.00	12.00		5.25	1	
1888	1888 VULCAN MATERIALS (Madras)	Distribution	Unattended	46.00	12.00		5.25	1	
1889	1889 VULCAN MATERIALS (Norcross)	Distribution	Unattended	115.00	12.00		10.50	1	
1890	1890 W. G. JOHNSON PM	Distribution	Unattended	46.00	12.00		0.25	1	
1891	1891 W. L. BONNELL #1	Distribution	Unattended	46.00	0.48		5.60	2	
1892	1892 W. L. BONNELL #2	Distribution	Unattended	46.00	0.48		7.00	2	
1893	1893 W. L. BONNELL #3	Distribution	Unattended	46.00	0.48		1.12	3	
1894	1894 W. M. WRIGLEY	Distribution	Unattended	115.00	4.00		42.00	4	

1895	1895 W. S. CATRETT PM	Distribution	Unattended	46.00	12.00		0.25	1	
1896	1896 WABASH	Distribution	Unattended	230.00	20.00		60.00	1	
1897	1897 WABASH	Distribution	Unattended	230.00	20.00		112.00	2	
1898	1898 WACO	Distribution	Unattended	46.00	12.00		7.00	1	
1899	1899 WALKER CO. INDUSTRIAL PARK	Distribution	Unattended	115.00	25.00		25.00	1	
1900	1900 WALLACE DAM	Generation	Attended	14.40	0.48			1	
1901	1901 WALLACE DAM	Generation	Attended	14.40	0.48		5.04	3	
1902	1902 WALLACE DAM	Generation	Attended	230.00	13.80		390.00	2	
1903	1903 WALMART	Distribution	Unattended	115.00	25.00		10.50	1	
1904	1904 WALTHOURVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
1905	1905 WALTHOURVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
1906	1906 WANSLEY	Generation	Attended	500.00			1149.00	3	
1907	1907 WANSLEY	Generation	Attended	4.00	0.48		1.12	2	
1908	1908 WANSLEY	Generation	Attended	20.00	4.00		160.00	4	
1909	1909 WANSLEY	Generation	Attended	500.00			1026.00	3	
1910	1910 WANSLEY	Generation	Attended	13.80	4.00		21.00	2	
1911	1911 WANSLEY CT	Generation	Attended	115.00	13.20		70.00	1	
1912	1912 WANSLEY FGD	Generation	Attended	230.00	13.80		120.00	2	
1913	1913 WANSLEY PUMPING	Distribution	Unattended	115.00	12.00		7.00	1	
1914	1914 WANSLEY PUMPING	Distribution	Unattended	115.00	4.00		11.20	2	
1915	1915 WARM SPRINGS ROAD	Distribution	Unattended	115.00	25.00		50.00	1	
1916	1916 WARRENTON	Distribution	Unattended	46.00	8.00		28.00	4	
1917	1917 WARRENTON AREA #1 PM	Distribution	Unattended	46.00	12.00		0.50	2	
1918	1918 WARRENTON AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1919	1919 WARRENTON AREA #3 PM	Distribution	Unattended	46.00	12.00		0.50	2	
1920	1920 WARRENTON AREA #5 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1921	1921 WARRENTON PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1922	1922 WARRENTON PRIMARY	Transmission	Unattended	115.00	46.00		22.40	1	
1923	1923 WASHINGTON	Distribution	Unattended	115.00	12.00		41.70	1	
1924	1924 WATKINS WOODS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1925	1925 WAVERLY PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1926	1926 WAX	Distribution	Unattended	46.00	12.00		5.25	1	
1927	1927 WAX	Distribution	Unattended	46.00	12.00		7.00	1	
1928	1928 WAYCROSS	Distribution	Unattended	115.00	12.00		21.00	2	
1929	1929 WAYCROSS MOULDED PRODUCTS	Distribution	Unattended	12.00	0.48		2.80	1	
1930	1930 WAYNE FARMS	Distribution	Unattended	46.00	0.48		7.00	1	

1931	1931 WAYNESBORO	Distribution	Unattended	115.00	12.00		25.00	1	
1932	1932 WAYNESBORO PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1933	1933 WELCOME ALL ROAD	Distribution	Unattended	230.00	25.00		120.00	2	
1934	1934 WELLS ALUMINUM #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1935	1935 WELLS ALUMINUM #2 PM	Distribution	Unattended	46.00	12.00		0.50	2	
1936	1936 WESLEYAN DRIVE	Distribution	Unattended	115.00	4.00		7.00	1	
1937	1937 WESLEYAN DRIVE	Distribution	Unattended	115.00	12.00		33.60	1	
1938	1938 WEST 11TH STREET	Distribution	Unattended	115.00	12.00		21.00	2	
1939	1939 WEST ATHENS	Distribution	Unattended	115.00	12.00		44.80	2	
1940	1940 WEST AUGUSTA	Distribution	Unattended	115.00	13.80		50.00	2	
1941	1941 WEST CRAWFORDVILLE	Distribution	Unattended	46.00	25.00		7.00	1	
1942	1942 WEST DALLAS	Distribution	Unattended	115.00	12.00		25.00	1	
1943	1943 WEST DALLAS	Distribution	Unattended	115.00	46.00		22.40	1	
1944	1944 WEST DALLAS	Distribution	Unattended	115.00	25.00		10.50	1	
1945	1945 WEST DICKEY PM	Distribution	Unattended	46.00	12.00		0.25	1	
1946	1946 WEST DICKEY PM	Distribution	Unattended	46.00	12.00		0.50	2	
1947	1947 WEST DUBLIN	Distribution	Unattended	230.00	12.00		67.20	2	
1948	1948 WEST END	Distribution	Unattended	115.00	20.00		100.00	2	
1949	1949 WEST GRIFFIN	Distribution	Unattended	46.00	12.00		14.00	2	
1950	1950 WEST MABLETON	Distribution	Unattended	115.00	12.00		40.00	1	
1951	1951 WEST MOULTRIE	Distribution	Unattended	46.00	12.00		5.25	1	
1952	1952 WEST POINT FOUNDRY & MACHINE	Distribution	Unattended	12.00	0.60		2.80	3	
1953	1953 WEYERHAEUSER (Colbert)	Distribution	Unattended	115.00	25.00		10.50	1	
1954	1954 WEYERHAEUSER (Savannah)	Distribution	Unattended	46.00	13.80		33.60	1	
1955	1955 WHEELER ROAD	Distribution	Unattended	230.00	12.00		33.60	1	
1956	1956 WHIRLWIND STEEL PD	Distribution	Unattended	46.00	0.48		2.50	1	
1957	1957 WHITE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1958	1958 WHITE BLUFF	Transmission	Unattended	115.00	13.80		50.00	2	
1959	1959 WHITEHALL	Distribution	Unattended	115.00	12.00		25.00	1	
1960	1960 WHITEMARSH ISLAND	Distribution	Unattended	115.00	13.80		14.00	1	
1961	1961 WHITEMARSH ISLAND	Distribution	Unattended	115.00	13.80		25.00	1	
1962	1962 WHITEOAK	Transmission	Unattended	115.00	46.00		50.00	1	
1963	1963 WHITEOAK	Transmission	Unattended	115.00	12.00		67.20	3	
1964	1964 WHITESBURG	Distribution	Unattended	46.00	12.00		5.25	1	
1965	1965 WHITESTONE PD	Distribution	Unattended	46.00	12.00		2.50	1	

1966	1966 WHITESTONE PD	Distribution	Unattended	46.00	12.00		0.25	1	
1967	1967 WHITEWATER	Distribution	Unattended	46.00	12.00		5.25	1	
1968	1968 WIDOW HILL PM	Distribution	Unattended	46.00	12.00		0.25	1	
1969	1969 WIEUCA ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
1970	1970 WILDER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1971	1971 WILLACOOCHEE CITY	Distribution	Unattended	46.00	12.00		7.00	1	
1972	1972 WILLIAMS CIRCLE SUBDIVISION PM	Distribution	Unattended	46.00	12.00		0.25	1	
1973	1973 WILLINGHAM DRIVE	Distribution	Unattended	115.00	20.00		60.00	1	
1974	1974 WILLINGHAM DRIVE	Distribution	Unattended	115.00	20.00		56.00	1	
1975	1975 WILLINGHAM DRIVE	Distribution	Unattended	115.00	20.00		50.00	1	
1976	1976 WILLOW RUN ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
1977	1977 WILLOW RUN ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
1978	1978 WILMINGTON ISLAND	Transmission	Unattended	115.00	46.00		50.00	2	
1979	1979 WILMINGTON ISLAND	Transmission	Unattended	115.00	13.80		80.00	2	
1980	1980 WILSON	Generation	Attended	230.00	13.80		25.00	1	
1981	1981 WILSON	Generation	Attended	4.00	0.48		0.84	1	
1982	1982 WILSON	Generation	Attended	13.80	13.80		44.80	2	
1983	1983 WILSON	Generation	Attended	230.00	13.80		145.00	1	
1984	1984 WILSON	Generation	Attended	13.80	0.48		2.52	3	
1985	1985 WILSON	Generation	Attended	4.00	2.40		2.25	1	
1986	1986 WILSON	Generation	Attended	13.80	0.48		1.68	1	
1987	1987 WILSON	Generation	Attended	230.00	13.20		244.00	2	
1988	1988 WINCHESTER SUBDIVISION PM	Distribution	Unattended	46.00	12.00		0.25	1	
1989	1989 WIND GAP FARMS	Distribution	Unattended	46.00	12.00		2.50	3	
1990	1990 WINDER PRIMARY	Distribution	Unattended	115.00	12.00		22.40	1	
1991	1991 WINDER PRIMARY	Distribution	Unattended	115.00	25.00		40.00	1	
1992	1992 WINDWARD	Distribution	Unattended	230.00	12.00		40.00	1	
1993	1993 WINDWARD	Distribution	Unattended	230.00	25.00		180.00	3	
1994	1994 WINDY HILL	Distribution	Unattended	115.00	20.00		112.00	2	
1995	1995 WINDY HILL	Distribution	Unattended	20.00	12.00		22.40	1	
1996	1996 WINN DIXIE PM (Powder Springs)	Distribution	Unattended	46.00	12.00		0.75	3	
1997	1997 WINN DIXIE (Atlanta)	Distribution	Unattended	20.00	12.00		12.50	2	
1998	1998 WINTERTHUR	Distribution	Unattended	115.00	20.00		56.00	1	
1999	1999 WINTERVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
2000	2000 WOODBINE	Distribution	Unattended	115.00	12.00		14.00	2	

2001	2001 WOODBURY	Distribution	Unattended	46.00	12.00		7.00	1	
2002	2002 WOODGRAIN MILLWORK	Distribution	Unattended	46.00	4.00		4.69	1	
2003	2003 WOODPECKER PM	Distribution	Unattended	46.00	12.00		0.25	1	
2004	2004 WOODVALLEY	Distribution	Unattended	115.00	12.00		33.60	1	
2005	2005 WRENS	Distribution	Unattended	46.00	12.00		5.25	1	
2006	2006 WRENS	Distribution	Unattended	46.00	12.00		4.20	1	
2007	2007 WRENS	Distribution	Unattended	46.00	12.00		5.25	1	
2008	2008 WRENS AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
2009	2009 WRENS PRIMARY	Distribution	Unattended	230.00	46.00		60.00	1	
2010	2010 WRENS PRIMARY	Distribution	Unattended	46.00	25.00		8.13	1	
2011	2011 WRIGHTSBORO ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
2012	2012 WRIGHTSVILLE	Distribution	Unattended	46.00	12.00		8.40	2	
2013	2013 WRIGHTSVILLE PRIMARY	Transmission	Unattended	230.00	46.00		33.60	1	
2014	2014 WYNNTON	Distribution	Unattended	115.00	12.00		40.00	1	
2015	2015 YALE RUBBER MANUFACTURING	Distribution	Unattended	46.00	0.48		2.80	1	
2016	2016 YAMAHA	Distribution	Unattended	115.00	25.00		10.50	1	
2017	2017 YAMAHA	Distribution	Unattended	115.00	25.00		60.00	1	
2018	2018 YATES 6&7	Generation	Attended	230.00	23.00		440.00	1	
2019	2019 YATES 6&7	Generation	Attended	20.00	4.00		20.00	2	
2020	2020 YATES 6&7	Generation	Attended	230.00			440.00	1	
2021	2021 YATES 6&7	Generation	Attended	20.00	4.00		28.00	2	
2022	2022 YATES COMMON	Transmission	Unattended	115.00	46.00		50.00	1	
2023	2023 YATES VILLAGE PD	Distribution	Unattended	46.00	12.00		2.50	1	
2024	2024 YONAH	Generation	Attended	115.00	6.60		30.00	3	
2025	2025 YONAH	Generation	Attended	115.00	12.00		10.50	1	
2026	2026 YOSHIDA	Distribution	Unattended	115.00	12.00		33.60	1	
2027	2027 YOUNG STATION	Distribution	Unattended	46.00	12.00		21.00	2	
2028	2028 ZEBULON ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
2029	2029 ZIPPER	Distribution	Unattended	115.00	12.00		25.00	1	
1	TotalDistributionSubstationMember						42,458		
2	TotalGenerationSubstationMember						31,660		
3	TotalTransmissionSubstationMember						5,480		
4	Total						79,598		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Accounting, Finance, Treasury	(a) Southern Company Services	(c) See Note	41,861,057
3	Administrative and General Services	Southern Company Services	(d) See Note	191,373,718
4	Information Technology	Southern Company Services	(e) See Note	279,749,008
5	Power Delivery Support Services	Southern Company Services	(f) See Note	248,917,808
6	Nuclear Administrative and Other Related Services	(b) Southern Nuclear Operating Company	174, 182.3, 426.1, 426.4, 426.5, 920, 921, 923, 931, 524	111,735,791
7	Nuclear Engineering Construction and Removal Serv.	Southern Nuclear Operating Company	107, 108, 120, 184	440,657,302
8	Nuclear Engineering Maintenance Services	Southern Nuclear Operating Company	528-532	64,839,176
9	Nuclear Engineering Operating Services	Southern Nuclear Operating Company	154, 517, 519-520, 523-525	276,288,746
10	Other Power Generation	Southern Nuclear Operating Company	546, 547-549, 551-553	1,071,153
11	Storm Assistance	Alabama Power Company	107,108,182.3,184,593,923	(g) 1,261,582
12	Railcar Usage	Alabama Power Company	151	259,696
13	Material Sale	Alabama Power Company	154	1,713,373
14	Storm Assistance	Mississippi Power Company	107,108,182.3,184,186,593,923	775,024
15	PPE Testing	Mississippi Power Company	510, 511, 535, 542, 551, 552, 566, 588	(h) 650,702
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Administrative & Other Related Services	Southern Company Services	146	20,901,774
22	Materials	Southern Company Services	146	11,060,353
23	Occupancy	Southern Company Services	146	6,711,264
24	Printing Service	Southern Company Services	146	224,881
25	Supply Chain Management	Southern Company Services	146	4,300,283
26	Vehicle Fleet Services	Southern Company Services	146	524,854

27	Material Sale	Alabama Power Company	146	6,754,951
28	Storm Assistance	Alabama Power Company	146	(394,559)
29	SERP/SBP Plan	Mississippi Power Company	146	1,104,732
30	Material Sale	Mississippi Power Company	146	504,225
42				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/20/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: NameOfAssociatedAffiliatedCompany

Southern Company Services
Southern Company Services, Inc. uses multiple allocation methodologies to allocate costs. These methodologies are designed to properly allocate cost on a causative basis and to prevent cross-subsidization among affiliated and non-affiliated companies. See Southern Company Services FERC Form 60 Schedule XXI for additional information. This note applies to Line Nos. 2, 3, 4, and 5 on page 429.

(b) Concept: NameOfAssociatedAffiliatedCompany

Southern Nuclear Operating Company
Georgia Power Company (GPC) is billed direct and allocated costs by Southern Nuclear Operating Company Inc. (SNC). SNC allocates costs to GPC using the Plant Basis Method. The Plant Basis Method of allocation is the factor determined by dividing one plant by total number of plants. GPC receives 2/3 of SNC allocated costs since GPC owns two and Alabama Power Company (APC) owns one of the three plants currently operated by SNC. This note applies to Line Nos. 6, 7, 8, 9, and 10 on page 429.

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounting, Finance & Treasury
165, 174, 184, 234, 408, 416, 421, 501, 506, 547, 549, 560, 566, 568, 570, 584, 588, 901, 903, 908, 912, 920, 921, 923, 926, 928

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Administrative and General Services
107, 108, 121, 151, 163, 165, 174, 181, 182.3, 183, 184, 186, 188, 232, 234, 253, 408, 415, 416, 417, 418, 421, 426.1, 426.3, 426.4, 426.5, 431, 500, 506, 535, 537, 539, 549, 557, 560-563, 566, 568-571, 573, 580-584, 586-588, 590-597, 901-903, 905, 907, 908, 911-913, 916, 920, 921, 923-926, 928, 929, 930, 931, 935

(e) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Information Technology
101, 107, 108, 146, 182.3, 184, 234, 408, 506, 524, 539, 549, 553, 566, 583, 586, 587, 588, 590, 591, 597, 901, 902, 905, 908, 912, 920, 921, 923, 926, 930, 931, 935

(f) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Power Delivery Support Services
107, 108, 120,182.3, 183, 186, 232, 404, 408, 412, 415, 426.1, 426.5, 431, 500-502, 505, 506, 509-514, 517, 519, 520, 524, 528-532, 535, 538-540, 542-549, 551-557, 560-562, 566, 568-571, 580-582, 586-588, 590-594, 596, 903, 908, 912, 920, 921, 923, 926, 930, 935

(g) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

APC is reporting $1,176,557 for Storm Assistance and GPC is reporting $1,261,582. The difference is due to timing.

(h) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Mississippi Power Company is reporting $648,076 for PPE Testing and GPC is reporting $650,702. The difference is due to the timing of invoicing and payments.

(i) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

APC is reporting $0 for Storm Assistance and GPC is reporting $394,559. The difference is due to timing.