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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
South Carolina Electric & Gas Company	**End of** 2017/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 and Licensees 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 Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(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.)

Reference 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

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, 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 _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed 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. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(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 http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

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 thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current 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, submit the electronic filing using the form submission software only. 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.

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. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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

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. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent South Carolina Electric & Gas Company	02 Year/Period of Report End of 2017/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)* 100 SCANA Parkway, Cayce, SC 29033-3712	
05 Name of Contact Person Lisa Honeycutt	06 Title of Contact Person Accounting Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 Operation Way - MC B131, Cayce, SC 29033-3701	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(803) 217-7416	(1) [X] An Original (2) [ ] A Resubmission	/ /

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)*
Iris N. Griffin	Iris N. Griffin	04/16/2018
02 Title Sr. VP, CFO and Treasurer		

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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".

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

James E. Swan, IV, Vice President and Controller
100 SCANA Parkway
Cayce, SC 29033-3712

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.

South Carolina - July 19, 1924

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.

Not Applicable

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

South Carolina - Electric, Gas

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...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2017/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent 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 beneficiearies for whom trust was maintained, and purpose of the trust.

The respondent is a wholly-owned subsidiary of SCANA Corporation (SCANA). SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA holds directly all of the capital stock of the respondent.

On January 2, 2018, SCANA and Dominion Energy agreed to merge in a stock-for-stock transaction in which SCANA shareholders would receive 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock. The completion of the merger is subject to the receipt of consents and approvals from government entities, which may impose conditions that could have an adverse effect on SCANA or SCE&G or could cause either SCANA or Dominion Energy to abandon the merger. The completion of the merger is also subject to a lack of changes in certain South Carolina laws that would be expected to have an adverse effect on SCANA and SCE&G.

For additional information, see Note 10 to the Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	South Caroina Fuel Company, Inc.	Acquires, owns, provides	None	
2		financing for and sells to		
3		SCE&G nuclear fuel,		
4		certain fossil fuels and		
5		emission allowances.		
6				
7	South Carolina Generating Company, Inc.	Owns A. M. Williams	None	
8		Generating Station and sells		
9		electricity solely to SCE&G.		
10				
11	SRFI, LLC	A single member LLC	None	
12		holding investments in		
13		companies involved with		
14		re-engineered fuel.		
15				
16	APOG, LLC	Provides technical,	None	
17		engineering and procurement		
18		support services to and for		
19		the benefit of members and		
20		their licensing, development		
21		and construction of AP1000		
22		nuclear power plants.		
23				
24				
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Canadys Refined Coal, LLC	Manufactures and sells	None	
2		refined coal to reduce		
3		emissions.		
4				
5	Brandon Shores Coaltech, LLC	Manufactures and sells	None	
6		refined coal to reduce		
7		emissions.		
8				
9	Louisa Refined Coal, LLC	Manufactures and sells	None	
10		refined coal to reduce		
11		emissions.		
12				
13	Carolinas Virginias Nuclear Power	A non-profit corporation	None	
14	Associates, Inc. (CVNPA)	formed in 1956 by member		
15		companies to jointly study		
16		economic ways to produce		
17		and utilize nuclear material		
18		and atomic energy. Operated		
19		a nuclear power plant from		
20		1963 - 1967.		
21				
22	Brunner Island Refined Coal, LLC	Manufactures and sells	None	
23		refined coal to reduce		
24		emissions.		
25				
26				
27				

Schedule Page: 103 Line No.: 1 Column: d

Control held by SCE&G under the terms of a fuel contract. The accounts of SCFC are fully consolidated herein.

Schedule Page: 103 Line No.: 7 Column: d

SCE&G has determined that it has a controlling financial interest in South Carolina Generating Company, Inc. under the terms of a Power Purchase Agreement. Accordingly, SCE&G consolidates the accounts of South Carolina Generating Company, Inc. for financial reporting under Generally Accepted Accounting Principles. Since South Carolina Generating Company, Inc. is a separate FERC reporting entity and per guidance from FERC staff, South Carolina Generating Company, Inc. has not been consolidated in this Form 1 report.

Schedule Page: 103 Line No.: 11 Column: d

SRFI, LLC is a single member LLC in which SCE&G is the sole member and no stock was issued.

Schedule Page: 103 Line No.: 16 Column: d

SCE&G holds a 25% interest in APOG, LLC. Other members include Duke Energy, Southern Nuclear Operating Company and Florida Power & Light Company.

Schedule Page: 103.1 Line No.: 1 Column: d

SCE&G holds a 40% interest in Canadys Refined Coal, LLC. The other member is AJG Coal, Inc.

Schedule Page: 103.1 Line No.: 5 Column: d

SCE&G holds a 10% interest in Brandon Shores Coaltech, LLC. The other member is AJG Coal, Inc.

Schedule Page: 103.1 Line No.: 9 Column: d

SCE&G holds a 10% interest in Louisa Refined Coal, LLC. Other members include AJG Coal, Inc. and LRC Holdings.

Schedule Page: 103.1 Line No.: 13 Column: d

SCE&G holds a 25% interest in CVNPA. Other members include Duke Power Company (Duke Energy Carolinas, LLC), Carolina Power & Light Company (Duke Energy Progress) and Virginia Electric and Power Company (Dominion Virginia Power).

Schedule Page: 103.1 Line No.: 22 Column: d

SCE&G holds a 20% interest in Brunner Island Refined Coal, LLC. The other member is AJG Coal, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
1			
2	Chairman and Chief Executive		
3	Officer (Separated from service 12/17)	Kevin B. Marsh	1,232,625
4	Executive Vice President and Chief Financial		
5	Officer (Through 12/17) Chief Executive		
6	Officer (Effective 1/18)	Jimmy E. Addison	544,627
7	Chief Operating Officer and President of Generation		
8	and Transmission (Separated from service 12/17)	Stephen A. Byrne	694,508
9	President of Retail Operations (Through 12/17)		
10	President and Chief Operating		
11	Officer (Effective 1/18)	W. Keller Kissam	400,068
12	President of Gas Operations	D. Russell Harris	219,314
13	Vice President of Finance (Through 3/17)		
14	Vice President of Finance and		
15	Treasurer (Effective 3/17) Senior Vice President,		
16	Chief Financial Officer		
17	Treasurer (Effective 1/18)	Iris N. Griffin	159,241
18	Senior Vice President - Risk Management and		
19	Corporate Compliance	Sarena D. Burch	243,042
20	Senior Vice President, General Counsel		
21	and Assistant Secretary (Separated from service 7/17)	Ronald T. Lindsay	196,163
22	Senior Vice President, General Counsel		
23	and Assistant Secretary (Effective 7/17)	Jim O. Stuckey	192,699
24	Senior Vice President Administration	Randall M. Senn	282,942
25	Senior Vice President and Chief Nuclear Officer	Jeffrey B. Archie	397,182
26	Senior Vice President of Economic Development,		
27	Governmental & Regulatory Affairs	Kenneth R. Jackson	264,944
28	Vice President of Governmental Affairs	Henry E. Barton, Jr.	137,138
29	Vice President of Human Resources	Annmarie C. Higgins	217,078
30	Vice President of Marketing and Communications	Catherine B. Love	191,267
31	Vice President of Electric Operations	William J. Turner, III	227,310
32	Vice President of Gas Operations	Felicia R. Howard	227,683
33	Vice President of Gas Services	M. Shaun Randall	96,853
34	Vice President of Fossil Hydro	James M. Landreth	270,742
35	Vice President of Customer Relations and Renewables	Daniel F. Kassis	229,267
36	Vice President of Customer Service	Samuel L. Dozier	167,995
37	Vice President of SCANA Support Services	Cedric F. Green	157,226
38	Vice President of Electric Transmission	Pandelis N. Xanthakos	187,472
39	Vice President Nuclear Construction and		
40	Startup (Separated from service 11/17)	Ronald A. Jones	274,763
41	Vice President of Nuclear		
42	Operations Units 2/3 (Separated from service 10/17)	Thomas D. Gatlin	295,392
43			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
1	Vice President of Nuclear Operations	George A. Lippard, III	265,807
2	Vice President and Treasurer		
3	(Separated from service 2/17)	Mark R. Cannon	68,061
4	Vice President and Secretary	Gina S. Champion	183,040
5	Vice President and Controller	James E. Swan, IV	229,765
6	Vice President and Chief Information Officer	Stacy O. Shuler, Jr.	188,706
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Schedule Page: 104   Line No.: 1   Column: c

Amounts reported reflect the portion of the officer's salary that was assigned to the respondent during the reporting period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	G. E. Aliff***	Reston, Virginia
2	J. A. Bennett***	Columbia, South Carolina
3	J. F. A. V. Cecil	Asheville, North Carolina
4	S. A. Decker	Mill Spring, North Carolina
5	D. M. Hagood***	Charleston, South Carolina
6	J. M. Micali *** (Retired effective 4/17)	Boston, Massachusetts
7	M. K. Sloan	Durham, North Carolina
8	L. M. Miller	Great Falls, Virginia
9	J.W. Roquemore***	Orangeburg, South Carolina
10	A. Trujillo***	Atlanta, Georgia
11	K.B. Marsh, Chairman	
12	and Chief Executive Officer of	
13	SCANA Corporation and SCE&G** (Resigned effective 12/17)	Cayce, South Carolina
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

Does the respondent have formula rates? [X] 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	FERC Proceeding
1	Schedule 1, Schedule 7, Schedule 8, Attachment H	ER10-516
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)?

[X] Yes

[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170515-5198	05/15/2017	ER10-516	Annual Update Informational Filing	Schedule 1, 7, 8, Attachment H
2					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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).	Schedule	Column	Line No
1	323	Electric Operation and Maintenance Expenses	b	197
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Page 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. One 20-year municipal electric and gas franchise agreement was renewed during the first quarter of 2017 without payment of consideration.

Two 20-year municipal electric only franchise agreements were renewed during the second quarter of 2017 without payment of consideration.

One 20-year municipal electric only franchise agreement was renewed during the third quarter of 2017 without payment of consideration.

One 20-year municipal electric and gas franchise agreement was renewed during the third quarter of 2017 without payment of consideration.

Three 30-year municipal electric and gas franchise agreements were renewed during the fourth quarter of 2017 without payment of consideration.

2. As previously discussed on page 102, on January 2, 2018, SCANA and Dominion Energy agreed to merge in a stock-for-stock transaction in which SCANA shareholders would receive 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock. The completion of the merger is subject to the receipt of consents and approvals from government entities, which may impose conditions that could have an adverse effect on SCANA or SCE&G or could cause either SCANA or Dominion Energy to abandon the merger. The completion of the merger is also subject to a lack of changes in certain South Carolina laws that would be expected to have an adverse effect on SCANA and SCE&G.

For additional information, see Note 10 to the Financial Statements.

3. None

4. None

5. None

6. The Company's obligations under short-term borrowing arrangements on the respective Balance Sheet dates were as follows:

12/31/2017	12/31/2016
$251,600,000	$804,321,000

Such short-term borrowings have been authorized by FERC (Docket No. ES16-51-000).

During 2017, the Company borrowed and paid back $62,400,000 from the SCANA Utility Money Pool. The Company also invested $27,500,000 into the Money Pool. As of December 31, 2017 this investment into the Money Pool was still outstanding and the Company had no outstanding borrowings.

For additional information, see Notes 4, 6 and 7 to the Financial Statements.

7. None

8. None

9. See Notes 2 and 10 to the Financial Statements.

10. None

11. (Reserved)

12. Not Applicable

13. The following changes in Company Officers and Directors became effective during 2017:

Mark R. Cannon, Vice President and Treasurer separated from service February 28, 2017.

Iris N. Griffin, Vice President of Finance, was appointed Vice President of Finance and Treasurer.

Ronald T. Lindsay, Senior Vice President, General Counsel and Assistant Secretary separated from service July 1, 2017.

James M. Micali retired from the Company's Board of Directors.

Jim O. Stuckey was appointed Senior Vice President, General Counsel and Assistant Secretary effective July 1, 2017.

Thomas D. Gatlin, Vice President of Nuclear Operations Units 2 and 3, separated from service October 31, 2017.

Ronald A. Jones, Vice President of Nuclear Construction and Startup, separated from service November 3, 2017.

Kevin B. Marsh, Chairman and Chief Executive Officer separated from service December 31, 2017.

Stephen A. Byrne, Chief Operating Officer and President of Generation and Transmission separated from service December 31, 2017.

The following changes in Officers and Directors became effective on January 1, 2018:

Jimmy E. Addison, Executive Vice President and Chief Financial Officer was appointed Chief Executive Officer.

W. Keller Kissam, President of Retail Operations, was appointed President and Chief Operating Officer of SCE&G.

Iris N. Griffin, Vice President of Finance and Treasurer, was appointed Sr. Vice President, Chief Financial Officer and Treasurer.

D. Maybank Hagood, Lead Independent Director, was appointed Non-Executive Chairman of the Board of Directors.

14. Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	200-201	11,454,443,398	10,808,517,861
3	Construction Work in Progress (107)	200-201	345,622,588	4,808,038,309
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,800,065,986	15,616,556,170
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,394,083,931	4,271,191,389
6	Net Utility Plant (Enter Total of line 4 less 5)		7,405,982,055	11,345,364,781
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	64,240,405	144,178,325
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		61,453,316	72,615,225
9	Nuclear Fuel Assemblies in Reactor (120.3)		216,049,432	223,723,883
10	Spent Nuclear Fuel (120.4)		753,448,656	673,993,828
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	887,336,035	843,261,889
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		207,855,774	271,249,372
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,613,837,829	11,616,614,153
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		72,485,640	69,793,932
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,040,926	1,064,999
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	1,646,310	2,856,380
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		60,809	61,516
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		135,788,950	122,840,806
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	70,585,791
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		208,940,783	265,073,426
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		279,635,557	160,445,414
36	Special Deposits (132-134)		507,059	187,012
37	Working Fund (135)		57,125	60,525
38	Temporary Cash Investments (136)		110,000,000	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		243,360,145	249,194,592
41	Other Accounts Receivable (143)		282,713,769	155,928,285
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,920,820	3,239,931
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		32,334,238	4,731,796
45	Fuel Stock (151)	227	49,154,758	46,289,912
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	139,564,723	134,522,151
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	633,469	640,580

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

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)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		10,674,912	11,124,020
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		7,308,627	7,705,351
57	Prepayments (165)		81,050,581	87,029,102
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		100,624	121,727
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		140,351,290	117,626,653
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		53,538,514	70,585,791
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	70,585,791
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,427,064,571	972,367,189
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,704,462	35,470,866
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	106,798,654	118,538,678
72	Other Regulatory Assets (182.3)	232	1,760,401,980	1,903,279,248
73	Prelim. Survey and Investigation Charges (Electric) (183)		218,472	709,896
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	4,116,066,676	165,241,815
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		13,973,993	15,116,379
82	Accumulated Deferred Income Taxes (190)	234	1,067,419,781	289,147,004
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		7,098,584,018	2,527,503,886
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		16,348,427,201	15,381,558,654

Schedule Page: 110 Line No.: 3 Column: c

As further described in Note 10 to the Financial Statements, on July 31, 2017 the Company determined to stop the construction of the New Nuclear Units that were being constructed at V.C. Summer Station. As a result of that decision, project costs of approximately $3.976 billion, which is net of an estimated impairment loss of $670 million, have been reclassified from account 107 - Construction Work in Progress to account 186 - Miscellaneous Deferred Debits. The estimated impairment loss of $670 million was recorded to account 426.5 - Other Deductions. The Company plans to file for authorization from the FERC to reclassify the project costs from account 186 - Miscellaneous Deferred Debits to account 182.2 - Unrecovered Plant and Regulatory Study Costs once a determination regarding retail rate recovery is made by the SCPSC.

Schedule Page: 110 Line No.: 78 Column: c

As further described in Note 10 to the Financial Statements, on July 31, 2017 the Company determined to stop the construction of the New Nuclear Units that were being constructed at V.C. Summer Station. As a result of that decision, project costs of approximately $3.976 billion, which is net of an estimated impairment loss of $670 million, have been reclassified from account 107 - Construction Work in Progress to account 186 - Miscellaneous Deferred Debits. The estimated impairment loss of $670 million was recorded to account 426.5 - Other Deductions. The Company plans to file for authorization from the FERC to reclassify the project costs from account 186 - Miscellaneous Deferred Debits to account 182.2 - Unrecovered Plant and Regulatory Study Costs once a determination regarding retail rate recovery is made by the SCPSC.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2017/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)	250-251	576,405,122	576,405,122
3	Preferred Stock Issued (204)	250-251	100,000	100,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	2,288,167,716	2,288,167,716
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	4,335,379	4,335,379
11	Retained Earnings (215, 215.1, 216)	118-119	1,982,337,445	2,481,211,937
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-3,707,328	-2,973,265
16	Total Proprietary Capital (lines 2 through 15)		4,838,967,576	5,338,576,131
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,928,770,000	4,928,770,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	245,843	265,579
22	Unamortized Premium on Long-Term Debt (225)		23,631,297	24,319,529
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		23,429,665	24,038,677
24	Total Long-Term Debt (lines 18 through 23)		4,929,217,475	4,929,316,431
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		22,381,185	20,678,011
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		7,489,713	7,859,531
29	Accumulated Provision for Pensions and Benefits (228.3)		219,027,661	233,863,772
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		4,354,555	3,371,455
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		516,256,431	509,434,012
35	Total Other Noncurrent Liabilities (lines 26 through 34)		769,509,545	775,206,781
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		251,600,000	804,321,000
38	Accounts Payable (232)		232,420,927	233,861,353
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		61,528,231	90,213,959
41	Customer Deposits (235)		61,599,964	60,283,425
42	Taxes Accrued (236)	262-263	203,354,563	190,023,234
43	Interest Accrued (237)		66,108,090	66,075,852
44	Dividends Declared (238)		80,600,000	77,500,000
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2017/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

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)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		8,451,440	8,495,957
48	Miscellaneous Current and Accrued Liabilities (242)		57,499,117	64,185,149
49	Obligations Under Capital Leases-Current (243)		5,851,966	5,341,366
50	Derivative Instrument Liabilities (244)		4,904,707	29,862,614
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		4,354,555	3,371,455
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,029,564,450	1,626,792,454
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	20,800,600	22,188,300
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	73,712,230	60,685,179
60	Other Regulatory Liabilities (254)	278	2,486,076,598	238,845,948
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	11,745,000	12,039,300
63	Accum. Deferred Income Taxes-Other Property (282)		970,043,127	2,003,667,530
64	Accum. Deferred Income Taxes-Other (283)		1,218,790,600	374,240,600
65	Total Deferred Credits (lines 56 through 64)		4,781,168,155	2,711,666,857
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		16,348,427,201	15,381,558,654

Schedule Page: 112   Line No.: 60   Column: c

Includes proceeds received under or arising from the monetization of the Settlement Agreement dated as of July 27, 2017 with Toshiba Corporation of approximately $1.095 billion, net of certain expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 data in column (k). 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) the quarter to date 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) the quarter to date 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
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,070,213,672	2,986,197,254		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,377,431,608	1,346,876,575		
5	Maintenance Expenses (402)	320-323	148,714,889	147,981,511		
6	Depreciation Expense (403)	336-337	262,071,048	254,702,412		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	11,121,772	8,989,523		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	860,418	860,418		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		18,061,442	18,061,442		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		9,647,937	5,655,182		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	239,637,931	227,416,255		
15	Income Taxes - Federal (409.1)	262-263	-287,518,299	-149,609,400		
16	- Other (409.1)	262-263	-17,549,914	-19,006,840		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,152,787,108	673,023,500		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,021,517,332	255,031,632		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,387,700	-1,392,200		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,892,360,908	2,258,526,746		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,177,852,764	727,670,508		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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 made to the utility's 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 or costs to which the 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 recover amounts paid 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 proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders 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, including the basis of 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 this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,664,426,229	2,619,373,876	405,787,443	366,823,378			2
						3
1,111,120,367	1,100,037,139	266,311,241	246,839,436			4
138,546,996	138,310,848	10,167,893	9,670,663			5
234,209,753	228,393,600	27,861,295	26,308,812			6
						7
9,978,891	8,037,130	1,142,881	952,393			8
854,201	854,201	6,217	6,217			9
18,061,442	18,061,442					10
						11
9,647,937	5,655,182					12
						13
211,057,625	200,637,124	28,580,306	26,779,131			14
-289,065,139	-144,978,100	1,546,840	-4,631,300			15
-17,737,587	-18,767,040	187,673	-239,800			16
1,118,569,408	641,198,000	34,217,700	31,825,500			17
1,003,798,532	241,225,732	17,718,800	13,805,900			18
-1,275,100	-1,279,600	-112,600	-112,600			19
						20
						21
						22
						23
						24
1,540,170,262	1,934,934,194	352,190,646	323,592,552			25
1,124,255,967	684,439,682	53,596,797	43,230,826			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,177,852,764	727,670,508		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		6,833,944	7,423,708		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		4,132,980	4,907,731		
33	Revenues From Nonutility Operations (417)		234,240	92,172		
34	(Less) Expenses of Nonutility Operations (417.1)		647,448	673,974		
35	Nonoperating Rental Income (418)		157,106	150,223		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-5,611,117	-4,095,182		
37	Interest and Dividend Income (419)		15,924,823	5,458,249		
38	Allowance for Other Funds Used During Construction (419.1)		14,753,860	26,082,377		
39	Miscellaneous Nonoperating Income (421)		20,522,136	16,068,854		
40	Gain on Disposition of Property (421.1)		1,617,902	621,436		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		49,652,466	46,220,132		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		33,834	33,834		
45	Donations (426.1)		2,085,926	3,245,411		
46	Life Insurance (426.2)		-10,906	28,544		
47	Penalties (426.3)		128,377			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,490,461	1,535,302		
49	Other Deductions (426.5)		1,137,874,457	8,827,081		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,142,602,149	13,670,172		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	708,404	660,927		
53	Income Taxes-Federal (409.2)	262-263	87,178,862	-6,033,035		
54	Income Taxes-Other (409.2)	262-263	17,494,431	485,364		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-25,063,011	5,673,000		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	83,203,100	7,892,900		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-2,884,414	-7,106,644		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-1,090,065,269	39,656,604		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		264,157,990	253,679,997		
63	Amort. of Debt Disc. and Expense (428)		2,375,415	2,940,265		
64	Amortization of Loss on Reaquired Debt (428.1)		1,142,386	1,142,386		
65	(Less) Amort. of Premium on Debt-Credit (429)		688,233	662,287		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		6,717,638	6,296,983		
68	Other Interest Expense (431)		14,152,269	9,290,728		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		15,295,478	18,052,443		
70	Net Interest Charges (Total of lines 62 thru 69)		272,561,987	254,635,629		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		-184,774,492	512,691,483		
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)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		-184,774,492	512,691,483		

Schedule Page: 114 Line No.: 4 Column: g

Includes depreciation charges of $9,016,948, amortization charges of $2,448,079 and property taxes of $2,433,369 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: h

Includes depreciation charges of $8,806,401, amortization charges of $2,345,890 and property taxes of $2,375,729 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: i

Includes depreciation charges of $851,265, amortization charges of $206,780 and property taxes of $205,506 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: j

Includes depreciation charges of $935,326, amortization charges of $200,122 and property taxes of $202,680 billed from SCANA Services.

Schedule Page: 114 Line No.: 49 Column: c

As further described in Note 10 to the Financial Statements, on July 31, 2017 the Company determined to stop the construction of the New Nuclear Units that were being constructed at V.C. Summer Station. As a result of that decision, the Company has recognized a pre-tax impairment loss of approximately $1.118 billion. This amount includes a pre-tax impairment loss of $670 million with respect to the probable disallowance of project costs, a pre-tax impairment loss of $361 million to write off costs that had been previously deferred, primarily as regulatory assets, in connection with the project and a pre-tax impairment loss of approximately $87 million to reduce to estimated fair value the carrying value of nuclear fuel acquired for use in Units 2 and 3.

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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		2,402,218,221	2,193,031,209
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		-179,163,375	516,786,665
17	Appropriations of Retained Earnings (Acct. 436)			
18	See Note 3 to Financial Statements	215.1	-14,951,261	(6,554,471)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-14,951,261	(6,554,471)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31		238	-314,100,000	(296,950,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-314,100,000	(296,950,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-5,611,117	(4,095,182)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,888,392,468	2,402,218,221
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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)
41				
42				
43				
44				
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)		93,944,977	78,993,716
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		93,944,977	78,993,716
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,982,337,445	2,481,211,937
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		-5,611,117	(4,095,182)
51	(Less) Dividends Received (Debit)			
52	Funded Equity Method Losses		5,611,117	4,095,182
53	Balance-End of Year (Total lines 49 thru 52)			

Schedule Page: 118 Line No.: 50 Column: c

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

Schedule Page: 118 Line No.: 52 Column: c

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Instruction 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)	-184,774,492	512,691,483
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	262,167,966	254,816,443
5	Amortization of Utility Plant and Acquisition Adjustment	12,016,024	9,883,775
6	Amortization - DER, Muni Franchise, Unrecovered Plt & OCI	27,864,306	23,886,561
7	Amortization of Nuclear Fuel	44,074,146	56,467,219
8	Deferred Income Taxes (Net)	-981,847,080	466,437,214
9	Investment Tax Credit Adjustment (Net)	-1,387,700	-1,392,200
10	Net (Increase) Decrease in Receivables	-163,764,313	-106,019,875
11	Net (Increase) Decrease in Inventory	-53,996,507	-33,502,669
12	Net (Increase) Decrease in Allowances Inventory	7,111	15,563
13	Net Increase (Decrease) in Payables and Accrued Expenses	-40,510,180	-133,163,069
14	Net (Increase) Decrease in Other Regulatory Assets	-197,706,638	-58,647,509
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,170,546,510	35,920,913
16	(Less) Allowance for Other Funds Used During Construction	14,753,860	26,082,377
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	1,128,083,849	-92,480,187
19	Discount / Premium on Long-Term Debt	-79,220	-98,464
20	Carrying Cost Recovery	-33,492,681	-16,654,733
21	(Gain) / Loss of Disposition of Assets	-2,426,302	-1,315,217
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	970,020,939	890,762,871
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-898,307,764	-1,332,925,131
27	Gross Additions to Nuclear Fuel	-9,276,835	-71,594,316
28	Gross Additions to Common Utility Plant	-8,005,359	-11,090,849
29	Gross Additions to Nonutility Plant	-1,043,329	-613,377
30	(Less) Allowance for Other Funds Used During Construction	-14,753,860	-26,082,377
31	Other (provide details in footnote):		
32	Salvage Received	3,861,858	3,331,278
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-898,017,569	-1,386,810,018
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Proceeds from Sale of Fixed Assets and Investments	3,333,262	46,858,251
39	Investments in and Advances to Assoc. and Subsidiary Companies	-4,569,279	-5,345,411
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Investments in Money Pool	-27,500,000	
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Return of Investments from Utility Money Pool		9,420,000
54	Other Investments	1,093,383,014	10,391,301
55	Settlement of Interest Rate Swaps	-39,001,631	-113,015,868
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	127,627,797	-1,438,501,745
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		500,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Contributions from Parent	1,477,086	100,000,000
66	Net Increase in Short-Term Debt (c)		384,096,000
67	Other (provide details in footnote):		
68	Borrowings from Utility Money Pool	62,400,000	
69	Deferred Financing Costs / Long-Term Debt Issuance Costs	-244,668	-7,112,918
70	Cash Provided by Outside Sources (Total 61 thru 69)	63,632,418	976,983,082
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-5,973,411	-104,946,742
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Borrowings from Utility Money Pool	-62,400,000	
78	Net Decrease in Short-Term Debt (c)	-552,721,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-311,000,000	-291,750,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-868,461,993	580,286,340
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	229,186,743	32,547,466
87			
88	Cash and Cash Equivalents at Beginning of Period	160,505,939	127,958,473
89			
90	Cash and Cash Equivalents at End of period	389,692,682	160,505,939

Schedule Page: 120 Line No.: 18 Column: b

Includes ($14,836,111) for changes in the Company's net postretirement benefit obligation, $5,978,521 for Prepayments, ($44,416,038) for Cost of Removal, $1,316,539 for Customer Deposits, $1,118,103,792 for costs associated with the abandonment of the New Nuclear Units and various other Balance Sheet changes not presented as separate line items.

Schedule Page: 120 Line No.: 18 Column: c

Includes $46,996,753 for changes in the Company's net postretirement benefit obligation, ($4,551,567) for Prepayments, ($31,563,685) for Cost of Removal, $3,196,365 for Customer Deposits, $72,124,423 receivable for federal tax refund, and various other Balance Sheet changes not presented as separate line items.

Schedule Page: 120 Line No.: 26 Column: b

For the twelve months ended December 31, 2017, the Company added $4,387,323 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($3,769,924) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 26 Column: c

For the twelve months ended December 31, 2016, the Company added $11,568,550 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($3,119,005) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: b

For the twelve months ended December 31, 2017, the Company added $862,104 to its Common Utility Plant Property Account (118) and reduced the same account by ($491,238) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: c

For the twelve months ended December 31, 2016, the Company added $861,564 to its Common Utility Plant Property Account (118) and reduced the same account by ($516,814) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: b

For the twelve months ended December 31, 2017, the Company added $2,918,020 to its Nonutility Property Account (121) and reduced the same account by ($1,692,513) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: c

For the twelve months ended December 31, 2016, the Company added $2,277,134 to its Nonutility Property Account (121) and reduced the same account by ($1,390,535) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 54 Column: b

Nuclear Decommissioning Trust	($ 1,527,937)
Collateral Returned - Interest Rate Swaps	94,300,000
Collateral Posted - Interest Rate Swaps	(94,300,006)
Deposits to Like Kind Exchange Escrow Account	(330,041)
Withdrawals from Like Kind Exchange Escrow Account	10,000
Monetization of Toshiba Settlement,net of costs	1,095,230,291
Other Investments	707
Total	$1,093,383,014

Schedule Page: 120 Line No.: 54 Column: c

Nuclear Decommissioning Trust	($ 1,658,080)
Collateral Returned - Interest Rate Swaps	727,377,348
Collateral Posted - Interest Rate Swaps	(714,958,687)
Deposits to Like Kind Exchange Escrow Account	(369,280)
Total	$ 10,391,301

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 Cormmission 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.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

DEFINITIONS

Abbreviations used in the notes for this Form No. 1 have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
CIAC	Contributions In Aid of Construction
Citibank	Citibank, N.A.
CO_2	Carbon Dioxide
Company	SCANA, together with its consolidated subsidiaries
Consortium	A consortium consisting of WEC and WECTEC
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DHEC	South Carolina Department of Health and Environmental Control
District Court	United States District Court for the District of South Carolina
DOE	United States Department of Energy
Dominion Energy	Dominion Energy, Inc.
DOR	South Carolina Department of Revenue
DSM Programs	Electric Demand Side Management Programs

ELG Rule	Federal effluent limitation guidelines for steam electric generating units
EMANI	European Mutual Association for Nuclear Insurance
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008, as amended by the October 2015 Amendment
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
FILOT	Fee in Lieu of Taxes
Fluor	Fluor Corporation
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
Interim Assessment Agreement	Interim Assessment Agreement dated March 28, 2017, as amended, among SCE&G, Santee Cooper, WEC and WECTEC
IRC	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
Joint Petition	Joint application and petition of SCE&G and Dominion Energy for review and approval of a proposed business combination as set forth in the Merger Agreement and for a prudency determination regarding the abandonment of the Nuclear Project and associated merger benefits and cost recovery plans, filed with the SCPSC on January 12, 2018
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards

MGP	Manufactured Gas Plant
Merger Agreement	Agreement and Plan of Merger, dated as of January 2, 2018, by and among Dominion Energy, Sedona Corp. (a wholly-owned subsidiary of Dominion Energy) and SCANA
MW or MWh	Megawatt or Megawatt-hour
NAV	Net Asset Value
NEIL	Nuclear Electric Insurance Limited
NOL	Net Operating Loss
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
Nuclear Project	Project to construct Unit 2 and Unit 3 under the EPC Contract
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
Price-Anderson	Price-Anderson Indemnification Act
Request	Request for Rate Relief filed by the ORS on September 26, 2017, as amended October 17, 2017
ROE	Return on Equity
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	SCANA Energy Marketing, Inc.
SCANA Services	SCANA Services, Inc.
SCE&G	South Carolina Electric & Gas Company
SCEUC	South Carolina Energy Users Committee
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan

SLED	South Carolina Law Enforcement Division
SO_2	Sulfur Dioxide
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Tax Act	An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (previously known as The Tax Cuts and Jobs Act) enacted on December 22, 2017
Toshiba	Toshiba Corporation, parent company of WEC
Toshiba Settlement	Settlement Agreement dated as of July 27, 2017, by and among Toshiba, SCE&G and Santee Cooper
TSR	Total Shareholder Return
Unit 1	Nuclear Unit 1 at Summer Station
Unit 2	Nuclear Unit 2 at Summer Station (abandoned prior to construction completion)
Unit 3	Nuclear Unit 3 at Summer Station (abandoned prior to construction completion)
VIE	Variable Interest Entity
WEC	Westinghouse Electric Company LLC
WECTEC	WECTEC Global Project Services, Inc. (formerly known as Stone & Webster, Inc.), a wholly-owned subsidiary of WEC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

The basic financial statements shown on pages 110 through 122 are prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. The significant differences from the GAAP requirements are related to the classification of certain assets and liabilities to include the classification of unrecovered nuclear project costs within regulatory assets for GAAP reporting purposes whereas these amounts are classified within miscellaneous deferred debits for FERC reporting purposes pending a future filing by the Company for FERC authorization to utilize the unrecovered plant and regulatory study costs account, the classification of the current portion of certain regulatory assets and liabilities, the classification of the current portion of long term debt, the classification of certain deferred income taxes, the removal of the presentation of unrecognized tax benefits, the classification of cost of removal and the classification of debt issuance costs. Also, the impairment loss and certain other charges associated with the abandonment of V.C. Summer Units 2 and 3 are classified within operating income for GAAP reporting purposes whereas these amounts are classified within nonoperating income (other deductions) for FERC reporting purposes. In addition, the accounts of GENCO are not consolidated herein, whereas they are so consolidated for GAAP reporting purposes.

These notes are based on the notes contained in SCE&G's Annual Report on Form 10-K filed with the SEC and reflect certain reclassifications from the Uniform System of Accounts presentation shown on pages 110 through 122. As such, certain amounts included in these notes will be different from amounts shown on pages 110 through 122.

Management has evaluated the impact of events occurring after December 31, 2017 up to February 22, 2018, the date that SCE&G's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 16, 2018. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in Fuel Company (which is considered to be a VIE) and accordingly, SCE&G's financial statements include the accounts of SCE&G and Fuel Company. The equity interests in Fuel Company are held solely by SCANA, SCE&G's parent.

Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

No estimate is made for legal costs expected to be incurred in connection with loss contingencies. Such costs are recorded when incurred.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. SCE&G calculated AFC using average composite rates of 3.9% for 2017, 4.7% for 2016, and 5.6% for 2015. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property, and in most cases, include provisions for future cost of removal. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. The composite weighted average depreciation rates for utility plant assets were 2.55% in 2017, 2.56% in 2016 and 2.55% in 2015.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in Fuel used in electric generation and recovered through the fuel cost component of retail electric rates.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Unit 1. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement. Unit 2 and Unit 3 have been reclassified from construction work in progress to a regulatory asset as a result of the decision to stop their construction. See additional discussion at Note 2.

As of December 31,	**2017**	**2016**	
	Unit 1	**Unit 1**	**Unit 2 and Unit 3**
Percent owned	66.7%	66.7%	55.0%
Plant in service	$ 1.5 billion	$ 1.3 billion	—
Accumulated depreciation	$ 637.6 million	$ 634.4 million	—
Construction work in progress	$ 110.1 million	$ 167.7 million	$ 4.2 billion

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for the units. These amounts totaled $53.8 million at December 31, 2017 and $76.2 million at December 31, 2016.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the balance sheet. Other planned major maintenance is expensed when incurred.

SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2017, and 2016, SCE&G incurred $20.5 million and $19.5 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, SCE&G accrues $17.2 million annually for its portion of the nuclear refueling outages scheduled from the spring of 2014 through the spring of 2020. Refueling outage costs incurred for which SCE&G was responsible totaled $1.8 million in 2016 in preparation for the Spring 2017 outage and $23.2 million in 2017.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The asset balance held in trust reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Temporary cash investments having original maturities of three months or less at time of purchase are considered to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements, treasury bills and money market funds.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Unbilled revenues totaled $140.3 million at December 31, 2017 and $117.6 million at December 31, 2016 for SCE&G. Other receivables consist primarily of amounts due from Santee Cooper related to the jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

SCE&G is included in the consolidated federal income tax returns of SCANA. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if such impacts are expected to be recovered from, or passed through to, customers of the

Company's regulated subsidiaries; otherwise, such adjustments are charged or credited to deferred income tax expense. Also, see Note 5 for a discussion of the impact of adjustments recorded upon enactment of the Tax Act.

Regulatory Assets and Regulatory Liabilities

SCE&G records costs that have been or are expected to be allowed in the ratemaking process in periods different from the periods in which the costs would be charged to expense, or record revenues in periods different from the periods in which the revenues would be recorded, by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations for refunds to customers are primarily classified on the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Certain deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as Receivables - Customer or Customer deposits and customer prepayments, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Premiums, discounts and debt issuance costs are presented within long-term debt and are amortized as components of interest charges over the terms of the respective debt issues. Gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Statement of Operations Presentation

Revenues and expenses of SCE&G's regulated activities (including those activities of segments described in Note 12) are presented within Operating Income (Loss), and all other activities are presented within Other Income (Expense).

Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not billed.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost proceedings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent proceedings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions.

Taxes billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

New Accounting Matters

Recently Adopted

In the first quarter of 2017, SCE&G adopted the following accounting guidance issued by the FASB. The adoption of this guidance had no impact on its financial statements except as indicated.

- Guidance issued in August 2014 requires an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern. See related disclosure at Note 10.
- Guidance issued in July 2015 requires most inventory to be measured at the lower of cost and net realizable value.
- Guidance issued in October 2016 requires entities to recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs.

Pending Adoption

In the first quarter of 2018, SCE&G will adopt the following accounting guidance issued by the FASB.

- Guidance issued in May 2014 for revenue arising from contracts with customers supersedes most prior revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides for a five-step analysis in determining when and how revenue is recognized, and requires revenue recognition to depict the transfer of promised goods or services to customers, based on the transfer of control, in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. In addition, this guidance requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The analysis of contracts with customers to which the guidance might be applicable has been completed and activities of the FASB's Transition Resource Group for Revenue Recognition, particularly as they relate to the treatment of CIAC, ARP and the collectability of revenue of utilities subject to rate regulation have been considered. Specifically, SCE&G has concluded that its use of CIAC is outside the scope of the new revenue recognition guidance. SCE&G has determined that aspects of SCE&G's WNA allow for revenue adjustments to be recognized prior to amounts being reflected in customer bills. These revenue adjustments, which give rise to regulatory assets or liabilities, represent ARPs that are outside the scope of the new guidance and will be reported as Other operating revenue separately from revenue from contracts with customers on the statement of operations. An evaluation of the enhanced disclosure requirements is being completed, including determining the appropriate disaggregation of revenue.

  SCE&G will adopt this guidance using the modified retrospective method, and comparative periods will not be restated. SCE&G does not anticipate that the adoption of this guidance will have any material impacts on its financial statements, but its adoption will result in additional disclosures. The adoption of this guidance will not result in a cumulative effect adjustment to beginning retained earnings.

- Guidance issued in January 2016 changes how entities measure certain equity investments and financial liabilities, among other things. Entities will be required to make a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective, with certain exceptions. SCE&G expects to adopt this guidance when required in the first quarter of 2018 and does not anticipate that its adoption will have a significant impact on its financial statements.

- Guidance issued in August 2016 is intended to reduce diversity in cash flow statement classification related to certain transactions, and entities must apply the guidance retrospectively to all periods presented. The adoption of this guidance will have no impact on the financial statements of SCE&G.

- Guidance issued in November 2016 clarifies how restricted cash should be presented on the statement of cash flows, and entities must apply the guidance retrospectively to all periods presented. The adoption of this guidance will have no impact on the financial statements of SCE&G.

- Guidance issued in March 2017 changes the required presentation of net periodic pension and postretirement benefit costs. Under this guidance, such costs will be separated into service cost components and other components. The service cost components will be presented in the same line item (or items) as other compensation costs arising from services rendered by employees during the period. The other components will be reported in the income statement separately from the service cost component and outside operating income. Only the service cost component will be eligible for capitalization in assets. Entities must apply this guidance on a retrospective basis for the presentation of the service cost component and the other components, and on a prospective basis for the capitalization of only the service cost component. As permitted, service cost and other costs disclosed in related footnotes to previously issued financial statements will be used when estimating retrospective changes for such costs in the income statements for prior periods. Due to regulatory overlay, non-service cost components related to regulated operations that are capitalized in assets under current accounting guidance will be deferred within regulatory assets in the future. As a result, the adoption of this guidance will not have a material impact on the financial statements of SCE&G.

SCE&G will adopt the following accounting guidance issued by the FASB when indicated below.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over 12 months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily on the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight-line basis, also depending on the nature of the assets and relative consumption. In January 2018, FASB amended this accounting guidance to provide an optional transition practical expedient that would allow adopters to not evaluate under the new guidance existing or expired land easements that were not previously accounted for as leases under existing guidance. The new guidance is effective for years beginning in 2019, and SCE&G does not anticipate that its adoption will impact its financial statements other than increasing amounts reported for assets and liabilities on the balance sheet and changing the place on its statements of operations on which certain expenses are recorded. No impact on net income (loss) is expected. The identification and analysis of leasing and related contracts to which the guidance might be applicable has begun. In addition, SCE&G has begun implementation of a third party software tool that will assist with initial adoption and ongoing compliance. Specifically, preliminary system configuration has been completed and data from certain leases are being entered.

In June 2016, the FASB issued accounting guidance requiring the use of a current expected credit loss impairment model for certain financial instruments. The new model is applicable to trade receivables and most debt instruments, among other financial instruments, and in certain instances may result in impairment losses being recognized earlier than under current guidance. SCE&G

must adopt this guidance beginning in 2020, including interim periods, though the guidance may be adopted in 2019. SCE&G has not determined when this guidance will be adopted or what impact it will have on its financial statements.

In August 2017, the FASB issued accounting guidance to simplify the application of hedge accounting. Among other things, the new guidance will enable more hedging strategies to qualify for hedge accounting, will allow entities more time to perform an initial assessment of hedge effectiveness, and will permit an entity to perform a qualitative assessment of effectiveness for certain hedges instead of a quantitative one. For cash flow hedges that are highly effective, all changes in the fair value of the derivative hedging instrument will be recorded in other comprehensive income and will be reclassified to earnings in the same period that the hedged item impacts earnings. Fair value hedges will continue to be recorded in current earnings, and any ineffectiveness will impact the income statement. In addition, changes in the fair value of a derivative will be recorded in the same income statement line as the earnings effect of the hedged item, and additional disclosures will be required related to the effect of hedging on individual income statement line items. The guidance must be applied to all outstanding instruments using a modified retrospective method, with any cumulative effect adjustment recorded to opening retained earnings as of the beginning of the first period in which the guidance becomes effective. SCE&G expects to adopt this guidance when required in the first quarter of 2019, though early adoption is permitted, and has not determined what impact such adoption will have on its financial statements.

In February 2018, the FASB issued accounting guidance allowing entities to reclassify from AOCI to retained earnings any amounts for stranded tax effects resulting from the Tax Act. The guidance must be applied either in the period of adoption or retrospectively to each period in which the effect of the change was recognized. SCE&G must adopt this guidance beginning in 2019, including interim periods, though the guidance may be adopted earlier. SCE&G has not determined when this guidance will be adopted or what impact it will have on its statements of financial position. No impact is expected on statements of operations or cash flows.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved SCE&G's participation in a DER program and recovery of related costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G is to implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. This nameplate capacity goal was achieved in 2017.

By order dated April 29, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties to decrease the total fuel cost component of retail electric rates. SCE&G reduced the total fuel cost component of retail electric rates to reflect lower projected fuel costs and to eliminate over-collected balances of approximately $61 million for base fuel and environmental costs over a 12-month period beginning with the first billing cycle of May 2016. SCE&G also began to recover projected DER program costs of approximately $6.9 million beginning with the first billing cycle of May 2016.

By order dated April 27, 2017, the SCPSC approved a settlement agreement among SCE&G, the ORS and the SCEUC, to increase the total fuel cost component of retail electric rates. SCE&G agreed to set its base fuel component to produce a projected under recovery of $61.0 million over a 12-month period beginning with the first billing cycle of May 2017. SCE&G also agreed to recover, over a 12-month period beginning with the first billing cycle of May 2017, projected DER program costs of approximately $16.5 million. Additionally, deferral of carrying costs will be allowed for base fuel component under-collected balances as they occur.

In October 2017, the SCPSC initiated its 2018 annual review of base rates for fuel costs. A public hearing for this annual review was held on April 10, 2018.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G has removed from rate base certain deferred income tax assets arising from capital expenditures related to Unit 2 and Unit 3 and accrued carrying costs on those amounts during periods in which they were not included in rate base. Such carrying costs were determined at SCE&G's weighted average long-term debt borrowing rate and were recorded as a regulatory asset and other income. Carrying costs totaled $18.8 million and $14.0 million during 2017 and 2016, respectively. As part of the impairment loss described in Note 10, accumulated carrying costs related to the Nuclear Project totaling $51.0 million were written off.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2017	First billing cycle of May	$37.0 million
2016	First billing cycle of May	$37.6 million
2015	First billing cycle of May	$32.0 million

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider was designed to allow SCE&G to recover projected pension costs, including under-collections, over a 12-month period, beginning with the first billing cycle in May 2016.

By order dated March 1, 2017, the SCPSC approved SCE&G's request to decrease its pension costs rider. The change in the pension rider decreased annual revenue by approximately $11.9 million. The pension rider is designed to allow SCE&G to recover projected pension costs, net of the previously over-collected balance, over a 12-month period, beginning with the first billing cycle in May 2017.

In December 2017, the ORS filed a petition with the SCPSC requesting all investor-owned utilities under the SCPSC's jurisdiction to report the impact of the Tax Act on their individual company's operations. The Tax Act contains provisions that lower the federal corporate tax rate from 35% to 21% effective January 1, 2018. The petition requested that utilities file an estimate of the Tax Act's effects on their most recent test year information available, including an explanation of those effects, and requested that utilities propose procedures for changing rates to reflect the impacts. Lastly, the petition requested that the SCPSC state in its order that rates in effect as of January 1, 2018, be subject to refund so that ratepayers receive the benefit of the tax law changes as of January 1, 2018. By order dated January 10, 2018, the SCPSC granted the ORS petition but did not state that rates in effect as of January 1, 2018 would be subject to refund. SCE&G provided its comments on January 24, 2018, concerning the timing and the format of the report. In March 2018, the ORS filed several recommendations with the SCPSC in response to the comments filed by utilities. These recommendations include that (1) SCE&G be required to defer for future ratemaking treatment all revenue requirements of the Tax Act from Janaury 1, 2018 through the effective date of new rates and that SCE&G should calculate the excess deferred taxes resulting from the reduction in the federal corporate tax rate and recognize as a deferred liability the estimated reduction in revenue requirement; (2) a reasonable interest be accrued on certain deferred amounts; (3) the SCPSC issue an order establishing the effective date for the implementation of the Tax Act as January 1, 2018 and that rates in effect as of January 1, 2018 may be subject to refund and requiring utilites to report no later than May 31, 2018, the estimated tax savings and when and how the utility will pass those savings to the ratepayer. On April 6, 2018, the ORS made an additional filing requesting that the SCPSC issue an order to the effect that (1) utilities which have committed to return the tax benefits of the Tax Act to customers effective January 1, 2018 elect or affirm their commitment to the SCPSC within ten days of the SCPSC's order and that such utilities report by May 1, 2018 the estimated savings and when and how the utility proposes to return such tax benefits, and (2) utilities contesting ratepayers right to recover such tax benefits effective January 1, 2018 be required to submit to the SCPSC within ten days of such order revised tariffs reflecting the estimated savings subject to true-up at a date to be determined by the SCPSC.

In January 2018, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved the filing would allow recovery of $37.0 million of costs and net lost revenues associated with DSM programs, along with an incentive to invest in such programs.

Electric - BLRA and Joint Petition

Under the BLRA, SCE&G filed revised rates with the SCPSC in 2015 and 2016 to incorporate the financing cost of incremental construction work in progress incurred for the Nuclear Project. Rate adjustments were based on SCE&G's updated cost of debt and capital structure and on an allowed ROE. No revised rates filing was pursued in 2017. The SCPSC approved recovery of the following amounts.

Increase	**Effective for bills rendered on and after**	**Amount**	**Allowed ROE**	
2.7%	November 27, 2016	$64.4 million	10.50%	*
2.6%	October 30, 2015	$64.5 million	11.00%	

*Applied prospectively for purposes of calculating revised rates under the BLRA on and after January 1, 2016.

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for Unit 2 and Unit 3 which had been developed in connection with the October 2015 Amendment (see Note 10). On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, the ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. By order dated February 28, 2017, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement, and that denial was not appealed.

The construction schedule approved by the SCPSC in November 2016 provided for contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively. The approved capital cost schedule included incremental capital costs that totaled $831 million, raising SCE&G's total project capital cost as then approved to an estimated amount of approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for the Nuclear Project from 10.5% to 10.25%. This revised ROE was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G could not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request was denied because SCE&G was out of compliance with its approved capital cost schedule or BLRA construction milestone schedule, subject to certain extensions. See also Abandoned Nuclear Project in Note 10.

Following WEC and WECTEC's bankruptcy filing on March 29, 2017, on June 22, 2017, the Friends of the Earth and the Sierra Club filed a complaint against SCE&G with the SCPSC, requesting that the SCPSC initiate a formal proceeding to direct SCE&G to immediately cease and desist from expending any further capital costs related to the construction of Unit 2 and Unit 3; to determine the prudence of acts and omissions by SCE&G in connection with this construction; to review and determine the prudence of abandonment of Unit 2 and Unit 3 and of the available least cost efficiency and renewable energy alternatives; and to remedy, abate and make due reparations for the rates charged to ratepayers related to the construction of Unit 2 and Unit 3. SCE&G filed its answer to the complaint and a motion to dismiss the complaint on July 19, 2017. On October 4, 2017, the SCPSC ordered proceedings under this complaint to be coordinated with proceedings for the Request filed by the ORS on September 26, 2017, described below, and allowed discovery to proceed. SCE&G's subsequent petition for rehearing and reconsideration was denied by the SCPSC on November 1, 2017. Proceedings related to this complaint have been consolidated with proceedings for the Request and the Joint Petition as described below.

On August 1, 2017, SCE&G filed the Abandonment Petition with the SCPSC which sought recovery of costs expended on the construction of Unit 2 and Unit 3, including certain costs incurred subsequent to SCE&G's last revised rates update, other costs under the abandonment provisions of the BLRA, and affirmation of SCE&G's decision to abandon construction of Unit 2 and Unit 3, among other things. Subsequently, SCE&G management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew the Abandonment Petition on August 15, 2017. See additional discussion at Note 10.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which had been previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed with the SCPSC a motion to amend its request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. A hearing on the parties' motions was held on December 12, 2017, and included the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, a large industrial customer, and several environmental groups.

By order dated December 20, 2017, the SCPSC denied SCE&G's Motion to Dismiss the Request and ordered that a hearing be set on the Request. In addition, the SCPSC ordered the ORS to perform a thorough inspection and audit, within 30 days, to determine the reasonableness of SCE&G's retail electric rates and to determine the reasonableness of SCE&G's statements regarding the potential effect that the removal of approximately $445 million in annual revenues, as requested by the ORS, could have on SCE&G. The SCPSC also granted the ORS's motion to amend the Request and consider the monetization of the Toshiba payout along with any other related factors that may be appropriate in determining a fair and reasonable rate. SCE&G intends to vigorously contest the Request, but cannot give any assurance as to the timing or outcome of this matter. Proceedings for the Request, the complaint filed by Friends of the Earth and the Sierra Club on June 22, 2017, and the Joint Petition discussed below have been consolidated.

On November 20, 2017, the ORS filed a letter with the SCPSC providing the ORS's preliminary list for stabilization and protection of the site where Unit 2 and Unit 3 are located and suggesting that the SCPSC have SCE&G respond to the ORS's November 20, 2017 letter and "explain why there is no violation of S.C. Code Ann. § 58-27-1300." The SCPSC granted the ORS's request, and SCE&G filed its response with the SCPSC on December 27, 2017.

On January 12, 2018, SCE&G and Dominion Energy filed with the SCPSC the Joint Petition for review and approval of a proposed business combination whereby SCANA would become a wholly-owned subsidiary of Dominion Energy. In the Joint Petition, approval of a customer benefits plan and a cost recovery plan for the Nuclear Project is also sought. Key provisions of this Joint Petition are summarized at Note 10. A hearing on this matter has not yet been scheduled.

On January 19, 2018, the ORS filed a report with the SCPSC in response to the SCPSC's order for a thorough inspection and audit of SCE&G's statements regarding potential adverse effects that could result from the removal of annual BLRA revenues. The ORS report relied on the analysis of bankruptcy counsel to conclude that the suspension of revised rates collections is unlikely to force SCE&G into bankruptcy. Notwithstanding this conclusion, the ORS predicted that there is 35% likelihood of an SCE&G bankruptcy if revised rates are terminated. The report also indicated that a full audit, as ordered by the SCPSC, would require upwards of 90 days to complete. SCE&G filed responses to the ORS report alleging numerous deficiencies in it, including that the report was not verified by an accountant and that it contained incorrect and misleading accounting conclusions, particularly with regard to the timing and magnitude of any impairment loss that would be required by GAAP. On January 31, 2018, the SCPSC ordered the ORS to complete this previously ordered thorough audit, inspection and examination of SCE&G's accounting records by March 30, 2018, encouraged them to employ the assistance of a utility financial professional if needed, and indicated that a request by the ORS for an extension of time would not be considered unreasonable. On February 7, 2018, the ORS requested clarification of the SCPSC's January 31, 2018 order. On February 15, 2018, the SCPSC instructed the ORS to evaluate a total of 8 different scenarios to be included in its report and instructed the ORS to inform them by March 2, 2018 whether the ORS needed additional time to complete its work. By letter dated March 2, 2018, the ORS informed the SCPSC that it anticipates completing its scope of work in June 2018.

<u>Gas</u>

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2017	2.2% Increase	$8.6 million
2016	1.2% Increase	$4.1 million
2015	No change	—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2017, 2016 and 2015 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent. See Electric - Base Rates for a discussion of the ORS petition related to the Tax Act, which also applies to Gas - SCE&G.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, SCE&G has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Except for certain unrecovered Nuclear Project costs and other unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	December 31, 2017	December 31, 2016
Regulatory Assets:		
Unrecovered Nuclear Project costs	$ 3,976	—

Accumulated deferred income taxes	—	$ 293
AROs and related funding	395	388
Deferred employee benefit plan costs	272	308
Deferred losses on interest rate derivatives	446	611
Other unrecovered plant	105	117
DSM Programs	59	59
Carrying costs on deferred tax assets related to the Nuclear Project	—	32
Pipeline integrity management costs	8	6
Environmental remediation costs	25	26
Deferred storm damage costs	24	20
Deferred costs related to uncertain tax position	—	15
Other	140	116
Total Regulatory Assets	$ 5,450	$ 1,991
Regulatory Liabilities:		
Monetization of guaranty settlement	$ 1,095	—
Accumulated deferred income taxes	876	$ 14
Asset removal costs	504	502
Deferred gains on interest rate derivatives	131	151
Total Regulatory Liabilities	$ 2,606	$ 667

Regulatory assets for unrecovered Nuclear Project costs have been recorded based on such amounts not being probable of loss in accordance with the accounting guidance on abandonments, whereas the other regulatory assets have been recorded based on the probability of their recovery. All regulatory assets represent incurred costs that may be deferred under applicable GAAP for regulated operations. The SCPSC or the FERC has reviewed and approved through specific orders certain of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by one of these regulatory agencies, including unrecovered nuclear project costs that are the subject of regulatory proceedings as further discussed in Note 10. In recording such costs as regulatory assets, management believes the costs would be allowable under existing rate-making concepts that are embodied in rate orders or current state law. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation, changes in state law, other changes in the regulatory environment or changes in accounting requirements, SCE&G could be required to write off all or a portion of its regulatory assets and liabilities. Such an event could have a material effect on SCE&G's financial statements in the period the write-off would be recorded.

Unrecovered Nuclear Project costs represents expenditures by SCE&G that have been reclassified from construction work in progress as a result of the decision to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs under the abandonment provisions of the BLRA or through other regulatory means, net of an estimated impairment loss and the transfer of certain assets described at Note 10.

Accumulated deferred income taxes contained within regulatory assets represent deferred tax liabilities that arise from utility operations that have not been included in customer rates. A portion of these regulatory assets related to depreciation and are netted within regulatory liabilities in the current period.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Unit 1 and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 107 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. SCE&G recovers deferred pension costs through utility rates of approximately $2 million annually for electric operations, which will end in 2044, and approximately $1 million annually for gas operations, which will end in 2027. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees up to approximately 11 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when such amounts are applied otherwise at the direction of the SCPSC. See also Note 10 for a discussion of certain amounts that were treated as impaired as of December 31, 2017.

Other unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent SCE&G's deferred costs associated with electric demand reduction programs, and such deferred costs are currently being recovered over approximately five years through an approved rate rider.

Carrying costs on deferred tax assets related to the Nuclear Project were calculated on accumulated deferred income tax assets associated with Unit 2 and Unit 3 which were not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs were written off as a part of the impairment loss in 2017. See also Note 10.

Pipeline integrity management costs represent operating and maintenance costs incurred to comply with federal regulatory requirements related to natural gas pipelines. SCE&G amortizes $1.9 million of such costs annually.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G. SCE&G's remediation costs are expected to be recovered over periods of up to approximately 17 years.

Deferred storm damage costs represent costs incurred in excess of amounts previously collected through SCE&G's SCPSC-approved storm damage reserve, and for which SCE&G expects to receive future recovery through customer rates.

Deferred costs related to uncertain tax position primarily represented the estimated amounts of domestic production activities deductions foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest expense and other costs arising from this uncertain tax position. SCE&G's current customer rates reflect the availability of domestic production activities deductions. These net deferred costs were written off as a part of the impairment loss in 2017. See Note 5 and Note 10.

Various other regulatory assets are expected to be recovered through rates over periods through 2047.

Monetization of guaranty settlement represents proceeds received under or arising from the monetization of the Toshiba Settlement, net of certain expenses.

Accumulated deferred income taxes contained within regulatory liabilities represent (i) excess deferred income taxes arising from the remeasurement of deferred income taxes upon the enactment of the Tax Act (certain of which are protected under normalization regulations and will be amortized over the remaining lives of related property, and certain of which will be amortized to the benefit of customers over a prescribed period as instructed by regulators) and (ii) deferred income taxes arising from investment tax credits, offset by (iii) deferred income taxes that arise from utility operations that have not been included in customer rates (a portion of which relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years). See also Note 5.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

3. COMMON EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2017 and 2016. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2017 and 2016.

SCE&G's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. SCE&G's bond indenture permits the payment of dividends on SCE&G's common stock only either (1) out of its Surplus (which as defined in the bond indenture equates to its retained earnings) or (2) in case there is no Surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, the Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2017 and 2016, retained earnings of approximately $93.9 million and $79.0 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term Debt

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

Dollars in millions	Maturity	2017 Balance	2017 Rate	2016 Balance	2016 Rate
First Mortgage Bonds (secured)	2018 - 2065	$ 4,840	5.80%	$ 4,840	5.79%
Industrial and Pollution Control Bonds (a)	2028 - 2038	89	3.44%	89	3.42%
Other	2018 - 2027	28	2.83%	26	2.76%
Total debt		4,957		4,955	
Current maturities of long-term debt		(556)		(5)	
Unamortized premium, net		1		—	
Unamortized debt issuance costs		(34)		(35)	
Total long-term debt, net		$ 4,368		$ 4,915	

(a) Includes variable rate debt of $34.6 million at December 31, 2017 (rate of 1.85%) and 2016 (rate of .76%) which are hedged by fixed swaps.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Long-term debt maturities will be $556 million in 2018, $5 million in 2019, $5 million in 2020, $34 million in 2021, and $3 million in 2022.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2017, the Bond Ratio was 5.24. Adjusted Net Earnings, as therein defined, excludes the impairment loss.

Lines of Credit (LOC) and Short-Term Borrowings

At December 31, 2017 and 2016, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	2017	2016
Lines of credit:		
Five-year, expiring December 2020	$ 700.0	$ 700.0
Fuel Company five-year, expiring December 2020	$ 500.0	$ 500.0
Three-year, expiring December 2018	$ 200.0	$ 200.0
Total committed long-term	$ 1,400.0	$ 1,400.0
Outstanding commercial paper (270 or fewer days)	$ 251.6	$ 804.3
Weighted average interest rate	1.92%	1.04%
Letters of credit supported by LOC	$ 0.3	$ 0.3
Available	$ 1,148.1	$ 595.4

SCE&G and Fuel Company are parties to credit agreements in the amounts and for the terms described above. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. The authority described herein will expire in October 2018. Were adverse developments to occur with respect to uncertainties highlighted elsewhere, the ability of SCE&G to secure renewal of this short-term borrowing authority may be adversely impacted.

SCE&G is obligated with respect to an aggregate of $34.6 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

SCE&G participates in a utility money pool with SCANA and another regulated subsidiary of SCANA. Money pool borrowings and investments bear interest at short-term market rates. SCE&G's interest income and expense from money pool transactions were not significant for any period presented. SCE&G had no outstanding money pool borrowings due to an affiliate for any period presented. At December 31, 2017 SCE&G had investments due from an affiliate of $28 million.

5. INCOME TAXES

Components of income tax expense (benefit) are as follows:

Millions of dollars	**2017**	**2016**	**2015**
Current taxes (benefit):			
Federal	$ (411)	$ 49	$ 207
State	(19)	12	31
Total current taxes (benefit)	(430)	61	238
Deferred tax (benefit) expense, net:			
Federal	255	162	(9)
State	(3)	19	(3)
Total deferred taxes (benefit)	252	181	(12)
Investment tax credits:			
Amortization of amounts deferred-state	—	—	(1)
Amortization of amounts deferred-federal	(1)	(2)	(2)
Total investment tax credits	(1)	(2)	(3)
Total income tax expense (benefit)	$ (179)	$ 240	$ 223

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	**2017**	**2016**	**2015**
Net income (loss)	$ (185)	$ 513	$ 466
Income tax expense (benefit)	(179)	240	223
Total pre-tax income (loss)	$ (364)	$ 753	$ 689

Income taxes (benefit) on above at statutory federal income tax rate	$ (127)	$ 264	$ 241
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	(9)	25	23
State investment tax credits (less federal income tax effect)	(5)	(5)	(6)
Allowance for equity funds used during construction	(5)	(9)	(9)
Amortization of federal investment tax credits	(1)	(2)	(2)
Section 45 tax credits	(8)	(8)	(9)
Domestic production activities deduction	(18)	(23)	(18)
Remeasurement of deferred taxes upon enactment of Tax Act	(1)	—	—
Other differences, net	(5)	(2)	3
Total income tax expense (benefit)	$ (179)	$ 240	$ 223

The tax effects of significant temporary differences comprising net deferred tax liability are as follows:

Millions of dollars	**2017**	**2016**
Deferred tax assets:		
Net operating loss and tax credit carryforward	$ 541	—
Toshiba settlement	273	—
Nondeductible accruals	42	$ 53

Asset retirement obligation, including nuclear decommissioning		129		195
Regulatory liability, non-property accumulated deferred income tax		54		—
Unamortized investment tax credits		7		14
Deferred fuel costs		—		17
Other		5		8
Total deferred tax assets		1,051		287
Deferred tax liabilities:				
Property, plant and equipment	$	976	$	1,753
Regulatory asset, unrecovered nuclear plant costs		962		—
Deferred employee benefit plan costs		53		92
Regulatory asset, asset retirement obligation		81		130
Regulatory asset, other unrecovered plant		27		45
Demand side management costs		16		23
Prepayments		19		29
Other		31		49
Total deferred tax liabilities		2,165		2,121
Net deferred tax liability	$	1,114	$	1,834

The federal and state tax credits and NOL carryforwards are presented below:

Millions of dollars		**December 31, 2017**	**Expiration Year**
Federal NOL Carryforwards	$	1,911	2037
Federal Tax Credits		35	2035 - 2037
Federal Charitable Carryforwards		5	2021 - 2022
State NOL Carryforwards		2,309	2037

State Charitable Carryforwards		2	2022
Total Tax Credits and NOL Carryforwards	$	4,262	

A valuation allowance is needed when it is more likely than not that all or a portion of a deferred tax asset will not be realized. In determining whether a valuation allowance is required, SCE&G considers such factors as prior earnings history, expected future earnings, carryback and carryforward periods, and tax strategies that could potentially enhance the likelihood of the realization of a deferred tax asset. Based on this evaluation, management has concluded that a valuation allowance is not needed.

In December 2017, the Tax Act was enacted, resulting in the remeasurement of all federal deferred income tax assets and liabilities to reflect a 21% federal statutory tax rate. Due to the regulated nature of SCE&G's operations, the effect of this remeasurement is primarily reflected in deferred income tax balances within regulatory liabilities (see Note 2). In connection with this remeasurement, however, SCE&G recorded a deferred income tax benefit of approximately $1 million in its statement of operations for the year ended December 31, 2017. Upon the eventual filing of SCE&G's 2017 income tax return, adjustments to deferred income taxes and excess deferred income taxes may be recorded; however, these adjustments are not expected to have a material impact on SCE&G's financial position, results of operations or cash flows.

SCE&G is included in the consolidated federal income tax returns of SCANA and files various applicable state and local income tax returns. The IRS has completed examinations of SCANA's federal returns through 2004, and SCANA's federal returns through 2009 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2016 as a result of claims discussed below. With few exceptions, SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes in Unrecognized Tax Benefits

Millions of dollars	**2017**	**2016**	**2015**
Unrecognized tax benefits, January 1	$ 350	$ 49	$ 16
Gross increases—uncertain tax positions in prior period	—	94	33
Gross decreases—uncertain tax positions in prior period	(273)	—	(2)
Gross increases—current period uncertain tax positions	21	207	2

Unrecognized tax benefits, December 31	$ 98	$ 350	$ 49

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In 2016 and 2017, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the design and construction activities of the Nuclear Project, in its 2015 and 2016 income tax returns. SCANA expects to claim similar deductions and credits in its 2017 tax return when it is filed in 2018. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models.

The IRS examined the claims in the amended returns, and as the examination progressed without resolution, SCE&G evaluated and recorded adjustments to unrecognized tax benefits; however, none of these changes materially affected SCE&G's effective tax rate. In October 2016, the examination of the amended tax returns progressed to the IRS Office of Appeals. In addition, the IRS has begun an examination of SCANA's 2013 through 2016 income tax returns, and it is expected that the IRS will also examine later returns.

These IRC Section 174 income tax deductions and IRC Section 41 credits were considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities were recorded as unrecognized tax benefits in the financial statements. Following the abandonment of the Nuclear Project, SCE&G anticipates that an abandonment loss deduction under IRC Section 165 will be claimed on the 2017 tax return. As such, certain of the IRC Section 174 deductions, to the extent they are denied, would instead be deductible in 2017 under IRC Section 165. The abandonment loss deduction is also considered an uncertain tax position; however, under relevant accounting guidance, no estimated unrecognized tax benefits were recorded as of December 31, 2017. The remaining unrecognized tax benefits include the impact of the IRC Section 174 deductions on domestic production activities deductions, credits, and certain unrecognized state tax benefits.

As of December 31, 2017, SCE&G has recorded an unrecognized tax benefit of $98 million ($19 million net of the impact of state deductions on federal returns, net of NOL and credit carryforwards, and net of receivables related to the uncertain tax positions). If recognized, $98 million of the tax benefit would affect SCE&G's effective tax rate. These unrecognized tax benefits are not expected to increase significantly within the next 12 months. It is also reasonably possible that these unrecognized tax benefits may decrease by $11 million within the next 12 months. No other material changes in the status of SCE&G's tax positions has occurred through December 31, 2017.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 and 2016 income tax returns and similar claims made in determining taxable income for 2017, and under the terms of an SCPSC order, SCE&G recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, with the expectation that these deferred costs and related interest thereon would be recoverable through customer rates in future years (see Note 2). However, as further described in Note 10, as of December 31, 2017, an impairment loss with respect to such deferred regulatory asset was recorded. SCE&G's current customer rates reflect the availability of domestic production activities deductions.

Also under the terms of an SCPSC order, estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 and 2016 income tax returns was deferred as a regulatory asset and was expected to be recoverable through customer rates in future years. An impairment loss with respect to these deferred amounts was also recorded as of December 31, 2017 (see Note 10). Otherwise, SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. Amounts recorded for such interest income, interest expense or tax penalties have not been material for any period presented.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Derivative instruments are recognized either as assets or liabilities in the statement of financial position and are measured at fair value. Changes in the fair value of derivative instruments are recognized either in earnings, as a component of other comprehensive income (loss) or, for regulated operations, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures, and in some cases risk limits, are established to control the level of market, credit, liquidity and operational and administrative risks. SCANA’s Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Risk Management Officer and other senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Interest rate swaps may be used to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which swaps designated as cash flow hedges are used to synthetically convert variable rate debt to fixed rate debt, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

Forward starting swap agreements that are designated as cash flow hedges may be used in anticipation of the issuance of debt. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated for accounting purposes as cash flow hedges and fair value changes and settlement amounts related to them have been recorded as regulatory assets and liabilities. Settlement losses on swaps have generally been amortized over the lives of subsequent debt issuances and gains have been amortized to interest expense or may be applied as otherwise directed by the SCPSC. However, see Note 10 for a discussion of the impairment of previously deferred regulatory asset amounts related to settlement losses on swaps that had been entered into for debt that was anticipated to be issued in connection with the Nuclear Project.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The aggregate notional amounts of the interest rate swaps were as follows:

Millions of dollars	December 31, 2017	December 31, 2016
Not designated as hedging instruments	$ 735.0	$ 1,285.0

The following table shows the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the balance sheet, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Fair Values of Derivative Instruments

Millions of dollars	Balance Sheet Location	Asset	Liability
As of December 31, 2017			
Not designated as hedging instruments			
Interest rate contracts			

	Derivative financial instruments	$ 54	$ 1
	Other deferred credits and other liabilities	—	4
Total		$ 54	$ 5
As of December 31, 2016			
Not designated as hedging instruments			
Interest rate contracts			
	Other deferred debits and other assets	$ 71	—
	Derivative financial instruments	—	$ 27
	Other deferred credits and other liabilities	—	3
Total		$ 71	$ 30

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the statements of income is as follows:

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)	Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount
Year Ended December 31, 2017			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2016			
Interest rate contracts	—	Interest expense	$ (1)
Year Ended December 31, 2015			
Interest rate contracts	—	Interest expense	$ (1)

As of December 31, 2017, SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.5 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Ineffectiveness on interest rate hedges designated as cash flow hedges was insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

Millions of dollars	Loss Deferred in Regulatory Accounts	Gain (Loss) Reclassified from Deferred Accounts into Income	
		Location	Amount
Year Ended December 31, 2017			
Interest rate contracts	$ (32)	Interest Expense	$ (3)
Interest rate contracts	—	Impairment Loss	(173)
Year Ended December 31, 2016			
Interest rate contracts	$ (34)	Other income	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2. For more discussion of amounts reclassified to Impairment Loss, see Note 10.

As of December 31, 2017, SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $2.7 million as an increase to interest expense.

Credit Risk Considerations

Certain derivative contracts contain contingent credit features. These features may include (i) material adverse change clauses or payment acceleration clauses that could result in immediate payments or (ii) the posting of letters of credit or termination of the derivative contract before maturity if specific events occur, such as a credit rating downgrade below investment grade or failure to post collateral.

Derivative Contracts with Credit Contingent Features

Millions of dollars	December 31, 2017	December 31, 2016
in Net Liability Position		
Aggregate fair value of derivatives in net liability position	$ 4.9	$ 21.3
Fair value of collateral already posted	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	4.9	21.3

in Net Asset Position		
Aggregate fair value of derivatives in net asset position	$ 53.5	$ 62.0
Fair value of collateral already posted	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	53.5	62.0

Information related to the offsetting derivative assets follows:

Derivative Assets

	Interest Rate Contracts	
Millions of dollars	**December 31, 2017**	**December 31, 2016**
Gross Amounts of Recognized Assets	$ 54	$ 71
Gross Amounts Offset in Statement of Financial Position	—	—
Net Amounts Presented in Statement of Financial Position	54	71
Gross Amounts Not Offset - Financial Instruments	—	(9)
Gross Amounts Not Offset - Cash Collateral Received	—	—
Net Amount	$ 54	$ 62
Balance sheet location		
Other current assets	$ 54	—
Other deferred debits and other assets	—	$ 71
Total	$ 54	$ 71

Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities

	Interest Rate Contracts	
Millions of dollars	**December 31, 2017**	**December 31, 2016**
Gross Amounts of Recognized Liabilities	$ 5	$ 30
Gross Amounts Offset in Statement of Financial Position	—	—

Net Amounts Presented in Statement of Financial Position	5	30
Gross Amounts Not Offset - Financial Instruments	—	(9)
Gross Amounts Not Offset - Cash Collateral Posted	—	—
Net Amount	$ 5	$ 21
Balance sheet location		
Derivative financial instruments	$ 1	$ 27
Other deferred credits and other liabilities	4	3
Total	$ 5	$ 30

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Available for sale securities are open-ended mutual funds registered with the SEC which maintain a stable NAV and are invested in government money market agreements or fully collateralized repurchase agreements. SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	December 31, 2017		December 31, 2016
Millions of dollars	**Level 1**	**Level 2**	**Level 2**
Assets:			
Available for Sale securities	$ 100	—	—
Interest rate contracts	—	$ 54	$ 71
Liabilities:			
Interest rate contracts	—	$ 5	$ 30

SCE&G had no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value were as follows:

	December 31, 2017		December 31, 2016	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**

Long-Term Debt	$ 4,923.7	$ 5,545.0	$ 4,919.9	$ 5,489.8

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

In connection with the impairment loss described in Note 10, SCE&G determined that the fair value of certain of its nuclear fuel was lower than its carrying amount. At December 31, 2017, this nuclear fuel had an estimated fair value of $43.8 million. This estimate is based on quoted prices received from vendors of nuclear fuel, which are considered to be Level 3 fair value measurements. SCE&G assesses the fair value of nuclear fuel in connection with the analysis of impairment described in Note 10 on a quarterly basis.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. SCE&G participates in SCANA's pension plan. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. SCE&G participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumption based on SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2017**	**2016**	**2017**	**2016**
Benefit obligation, January 1	$ 768.4	$ 724.0	$ 206.5	$ 191.2
Service cost	18.1	16.9	3.6	3.6
Interest cost	31.9	33.4	9.3	9.7
Plan participants' contributions	—	—	1.1	1.3
Actuarial loss	36.6	41.8	6.4	11.2
Benefits paid	(62.0)	(47.7)	(10.1)	(8.9)
Amounts Funded to parent	—	—	(1.3)	(1.6)
Benefit obligation, December 31	$ 793.0	$ 768.4	$ 215.5	$ 206.5

The accumulated benefit obligation for pension benefits was $769.7 million at the end of 2017 and $742.9 million at the end of 2016. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	**2016**	**2017**	**2016**
Annual discount rate used to determine benefit obligation	3.71%	4.22%	3.74%	4.30%

Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease gradually to 5.0% for 2023 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $1.3 million at December 31, 2017 and by $0.6 million at December 31, 2016. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $1.1 million at December 31, 2017 and by $0.6 million at December 31, 2016.

Funded Status

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**
Fair value of plan assets	$ 781.3	$ 732.9	—	—
Benefit obligation	793.0	768.4	$ 215.5	$ 206.5
Funded status	$ (11.7)	$ (35.5)	$ (215.5)	$ (206.5)

Amounts recognized on the balance sheets were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**
Current liability	—	—	$ (10.5)	$ (10.2)
Noncurrent liability	$ (11.7)	$ (35.5)	(205.0)	(196.3)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**
Net actuarial loss	$ 2.1	$ 1.9	$ 1.4	$ 1.0

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**
Net actuarial loss	$ 171.4	$ 208.8	$ 34.8	$ 28.6
Prior service cost	1.0	2.2	—	—
Total	$ 172.4	$ 211.0	$ 34.8	$ 28.6

In connection with the joint ownership of Summer Station, costs related to the pension benefit obligation attributable to Santee Cooper as of December 31, 2017 and 2016 totaled $21.4 million and $23.4 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2017 and 2016 totaled $14.7 million and $15.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	**2017**	**2016**
Fair value of plan assets, January 1	$ 732.9	$ 720.1
Actual return on plan assets	110.4	60.5
Benefits paid	(62.0)	(47.7)
Fair value of plan assets, December 31	$ 781.3	$ 732.9

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. SCANA uses a dynamic investment strategy for the management of the pension plan assets. This strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2017 and 2016 and the target allocation for 2018 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2018**	**2017**	**2016**
Equity Securities	58%	58%	57%
Fixed Income	33%	31%	32%
Hedge Funds	9%	11%	11%

For 2018, the expected long-term rate of return on assets will be 7.0%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active and passive returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2017 and 2016, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	**2017**	**2016**
Investments with fair value measure at Level 2:		
Mutual funds	$ 110	$ 115
Short-term investment vehicles	16	15
US Treasury securities	14	17

Corporate debt securities	84	76
Municipals	15	13
Total assets in the fair value hierarchy	$ 239	$ 236
Investments at net asset value:		
Common collective trust	$ 458	$ 418
Joint venture interests	84	79
Total investments at fair value	$ 781	$ 733

For all periods presented, assets with fair value measurements classified as Level 1 were insignificant, and there were no assets with fair value measurements classified as Level 3. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2017 or 2016.

Mutual funds held by the plan are open-ended mutual funds registered with the SEC. The price of the mutual funds' shares is based on its NAV, which is determined by dividing the total value of portfolio investments, less any liabilities, by the total number of shares outstanding. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. US Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Common collective trust assets and limited partnerships are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds' net assets at fair value by the units outstanding at each valuation date. Joint venture interests are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and not traded on a daily basis. The valuation of such multi-strategy hedge fund of funds is estimated based on the NAV of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may influence their fair value.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2018	$ 66.9	$ 10.7
2019	64.6	11.3
2020	63.9	11.9
2021	66.5	12.4
2022	72.0	12.8
2023-2027	303.0	67.7

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals at the end of 2023, no significant contributions to the pension plan are expected to be made for the foreseeable future based on current market conditions and assumptions.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Service cost	$ 18.1	$ 16.9	$ 19.3	$ 3.6	$ 3.6	$ 4.3

Interest cost	31.9	33.4	32.2	9.3	9.7	9.2
Expected return on assets	(46.7)	(47.4)	(52.2)	n/a	n/a	n/a
Prior service cost amortization	1.4	3.4	3.4	—	0.2	0.3
Amortization of actuarial losses	13.9	12.5	11.4	0.8	0.4	1.7
Net periodic benefit cost	$ 18.6	$ 18.8	$ 14.1	$ 13.7	$ 13.9	$ 15.5

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Current year actuarial (gain) loss	$ 0.3	—	$ 0.2	$ 0.5	$ 0.3	$ (0.3)
Amortization of actuarial losses	(0.1)	$ (0.1)	(0.1)	(0.1)	—	—
Amortization of prior service cost	—	—	(0.1)	—	—	—
Total recognized in OCI	$ 0.2	$ (0.1)	$ —	$ 0.4	$ 0.3	$ (0.3)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Current year actuarial (gain) loss	$ (24.8)	$ 26.3	$ 12.2	$ 6.9	$ 9.0	$ (13.7)
Amortization of actuarial losses	(12.5)	(11.2)	(10.4)	(0.7)	(0.3)	(1.4)

Amortization of prior service cost	(1.3)	(3.0)	(3.1)	—	(0.2)	(0.3)
Total recognized in regulatory assets	$ (38.6)	$ 12.1	$ (1.3)	$ 6.2	$ 8.5	$ (15.4)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			**Other Postretirement Benefits**		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate	4.22%	4.68%	4.20%	4.30%	4.78%	4.30%
Expected return on plan assets	7.25%	7.50%	7.50%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Health care cost trend rate	n/a	n/a	n/a	6.60%	7.00%	7.00%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2021	2021	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2018 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2018 are as follows:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 9.0	$ 1.4
Prior service cost	0.4	—
Total	$ 9.4	$ 1.4

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCANA sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. SCE&G participates in this plan. Contributions are matched 100% up to 6% of an employee’s eligible earnings. Such matching contributions made by SCE&G totaled $23.4 million in 2017, $22.9 million in 2016 and $21.8 million in 2015. Employee deferrals, matching contributions, and earnings on all contributions are fully vested and nonforfeitable at all times.

9. SHARE-BASED COMPENSATION

SCE&G participates in the SCANA LTECP which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2015-2017, 2016-2018 and 2017-2019 performance cycles provide for performance measurement and award determination based on performance over a single three-year cycle, with payment of awards being deferred until after the end of the three-year performance cycle. In each of these performance cycles, 30% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash, and 70% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Cash-settled liabilities related to earlier performance cycles totaled approximately $13.2 million in 2016 and $6.3 million in 2015.

Fair value adjustments for all performance cycles resulted in compensation expense (benefit) recognized in the statements of income totaling approximately $(6.2) million in 2017, $17.3 million in 2015 and $12.2 million in 2015. Such fair value adjustments also resulted in capitalized compensation costs $(0.9) million in 2017, $3.1 million in 2016 and $0.6 million in 2015. At December 31, 2017, SCE&G's unrecognized compensation cost, which is expected to be recognized over a weighted -average period of 18 months, was $3.9 million. Large declines in stock price and relative performance in 2017 resulted in reductions of liabilities previously accrued with respect to open performance cycles. In the event of consummation of the merger, additional compensation cost arising from these liability awards may also be recognized.

10. COMMITMENTS AND CONTINGENCIES

Abandoned Nuclear Project

SCE&G, on behalf of itself and as agent for Santee Cooper, entered into the EPC Contract with the Consortium in 2008 for the design and construction of Unit 2 and Unit 3. SCE&G's ownership share in these units is 55%. As discussed below, various difficulties were encountered in connection with the project. The ability of the Consortium to adhere to established budgets and construction schedules was affected by many variables, including unanticipated difficulties encountered in connection with project engineering and the construction of project components, constrained financial resources of the contractors, regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected time frames, the availability of labor and materials at estimated costs and the efficiency of project labor. There were also contractor and supplier performance issues, difficulties in timely meeting critical regulatory requirements, contract disputes, and changes in key contractors or subcontractors. These matters, and others more fully discussed below, were the subject of comprehensive analyses performed by the Company and Santee Cooper (see Contractor Bankruptcy Proceedings and Related Uncertainties below). Based on the results of the Company's analysis, and in light of Santee Cooper's decision to suspend construction on Unit 2 and Unit 3, on July 31, 2017, the Company determined to stop the construction of the units and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means.

EPC Contract and BLRA Matters

The Nuclear Project and SCE&G's related recovery of financing costs through rates has been subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC approved, among other things, a milestone schedule and a capital costs estimates schedule for Unit 2 and Unit 3. Pursuant to the BLRA, this approval constituted a final and binding determination that the units were used and useful for utility purposes, and that the capital costs associated with them were prudent utility costs and expenses and were properly included in rates, so long as Unit 2 and Unit 3 were constructed or were being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the Nuclear Project. As of December 31, 2017, financing costs on $3.5 billion of SCE&G's construction costs for the Nuclear Project, excluding related transmission assets, have been reflected in revised rates under the BLRA, with the last revised rates increase having gone into effect in November 2016. SCE&G estimates that revised rates collections that have accumulated as of December 31, 2017, including collections related to transmission assets expected to be placed into service, total approximately $1.9 billion.

As a result of the decision to abandon the Nuclear Project, amounts reclassified from construction work in progress into regulatory assets, net of impairments described below, are summarized as follows:

Unrecovered Nuclear Project Costs		**Millions of dollars**
Nuclear Project costs as of September 30, 2017, prior to impairment loss and excluding transmission assets	$	4,730
Less Impairment loss recorded in the third quarter of 2017 (See below)		210
Balance of unrecovered Nuclear Project costs as of September 30, 2017		4,520
Less Impairment loss recorded in the fourth quarter of 2017 (See below)		460
Less Nuclear Project and switchyard assets transferred for use by Unit 1		84
Balance of unrecovered Nuclear Project costs as of December 31, 2017 (See Note 2)	$	3,976

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued combined Construction and Operating Licenses in March 2012. In November 2012, and again in September 2015 and November 2016 (see discussion below), the SCPSC approved SCE&G's requested updates to the milestone schedule, revised contractual substantial completion dates, and increases in capital and other costs. As further discussed below, under the current regulatory construct in South Carolina, approval by the SCPSC of cost recovery under the abandonment provisions of the BLRA or through other means will be required as a consequence of the Company's determination on July 31, 2017 to cease construction of the Nuclear Project.

October 2015 Amendment and WEC's Engagement of Flour

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The amendment became effective in December 2015, at which time Fluor began serving as a subcontracted construction manager for the Consortium. The October 2015 Amendment provided SCE&G and Santee Cooper an option to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G's 55% portion being approximately $3.345 billion). This total amount to be paid would be reduced by amounts paid since June 30, 2015. SCE&G, on behalf of itself and as agent for Santee Cooper, elected the fixed price option, subject to SCPSC approval, on July 1, 2016

Among other things, the October 2015 Amendment revised the contractual guaranteed substantial completion dates of Unit 2 and Unit 3 to August 31, 2019 and August 31, 2020, respectively, and provided for development of a revised construction milestone payment schedule. In February 2017, WEC notified SCE&G that the contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively, which were reflected in the October 2015 Amendment, would not be met. Instead, WEC provided further revised estimated substantial completion dates of April 2020 and December 2020.

November 2016 SCPSC Order

In May 2016, SCE&G petitioned the SCPSC for approval of the updated construction and capital cost schedules for Unit 2 and Unit 3 which had been developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, the ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. By order dated February 28, 2017, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement, and that order was not appealed.

The construction schedule approved by the SCPSC in November 2016 provided for contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively. The approved capital cost schedule included incremental capital costs that totaled $831 million, raising SCE&G's total project capital cost as then approved to an estimated amount of approximately $6.8 billion including owner’s costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G’s allowed ROE for the Nuclear Project from 10.5% to 10.25%. This revised ROE was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. No such revised rates have been sought since that time.

Contractor Bankruptcy Proceedings and Related Uncertainties

On March 29, 2017, WEC and WECTEC, the two members of the Consortium, and certain of their affiliates filed petitions for protection under Chapter 11 of the U.S. Bankruptcy Code, citing a liquidity crisis arising from project contract losses attributable to the Nuclear Project and similar units being built for an unaffiliated company as a material factor that caused WEC and WECTEC to seek protection under the bankruptcy laws. As part of such filing, WEC and WECTEC publicly announced their inability to complete Unit 2 and Unit 3 under the terms of the EPC Contract.

In connection with the bankruptcy filing, SCE&G, Santee Cooper, WEC and WECTEC entered into an Interim Assessment Agreement under which engineering and construction continued on the project and under which SCE&G and Santee Cooper were provided the right to discuss project status with Fluor and other subcontractors and vendors and to obtain from them relevant project information and documents that had been previously contractually unavailable in order for SCE&G and Santee Cooper to perform comprehensive analyses regarding whether or how to proceed with the Nuclear Project. As part of the Interim Assessment Agreement, and to avoid an immediate rejection of the EPC Contract upon the filing of the bankruptcy case, WEC and WECTEC required SCE&G and Santee Cooper to make estimated weekly payments to WEC, WECTEC, subcontractors and vendors, irrespective of the fixed price provisions of the EPC Contract, to permit the time to conduct analyses. SCE&G and Santee Cooper agreed to pay specified costs incurred by the Consortium, Fluor, other subcontractors and vendors for work performed or services rendered while the Interim Assessment Agreement remained in effect.

During the period of the Interim Assessment Agreement, as amended and extended, SCE&G and Santee Cooper evaluated the various elements of the Nuclear Project, including forecasted costs and completion dates, while construction continued and SCE&G and Santee Cooper continued to make payments for such work.

As part of its evaluation, SCE&G considered that, as a result of the bankruptcy process (including WEC and WECTEC's public announcements that they could not perform under the terms of the EPC Contract), the EPC Contract would likely be rejected and that the benefit of the fixed-price terms provided by the EPC Contract would be lost. As such, any cost overruns that would have been absorbed by the Consortium would become the responsibility of SCE&G and Santee Cooper. Additionally, these cost increases and other costs identified by SCE&G would not be fully recoverable from the Consortium or from Toshiba under its payment guaranty or the related Toshiba Settlement, discussed below, and such costs would likely substantially exceed the amount of the Consortium's payment obligations guaranteed by Toshiba.

SCE&G also considered that even the newly revised substantial completion dates identified by WEC of April and December 2020 for Unit 2 and Unit 3, respectively, likely would not be met. As such, the electricity to be produced by each of the units would not qualify for nuclear production tax credits under Section 45J of the IRC. SCE&G's 55% share of these nuclear production tax credits for both Unit 2 and Unit 3 could have totaled as much as approximately $1.4 billion. Failure to meet the newly revised substantial completion dates identified by WEC would result in the nuclear production tax credits not being earned.

On September 1, 2017, SCE&G, for itself and as agent for Santee Cooper, filed with the Bankruptcy Court Proofs of Claim for unliquidated damages against each of WEC and WECTEC. The Proofs of Claim are based upon the anticipatory repudiation and material breach by the Consortium of the EPC Contract, and assert against WEC and WECTEC any and all claims that are based thereon or that may be related thereto. These claims were sold to Citibank on September 27, 2017 as part of the monetization transaction discussed below. Notwithstanding the sale of the claims, SCE&G and Santee Cooper remain responsible for any claims that may be made by WEC and WECTEC against them relating to the EPC Contract.

Toshiba Settlement and Subsequent Monetization

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and WECTEC, and in connection with the October 2015 Amendment, Toshiba, WEC’s parent company, reaffirmed its guaranty of WEC’s payment obligations. In satisfaction of such guaranty obligations, on July 27, 2017, the Toshiba Settlement was executed under which Toshiba was to make periodic settlement payments from October 2017 through September 2022 in the total amount of approximately $2.2 billion ($1.2 billion for SCE&G’s 55% share). The $2.2 billion is subject to offset for payments by WEC that have the effect of satisfying the liens on the project discussed below.

On September 27, 2017, the scheduled payments under the Toshiba Settlement, exclusive of the payment due in October 2017, were purchased by Citibank for a one-time upfront payment of $1.847 billion (approximately $1.016 billion for SCE&G's 55% share), including amounts related to the contractor liens discussed below. The initial payment was then received from Toshiba on October 2, 2017, as scheduled, in the amount of $150 million ($82.5 million for SCE&G's 55% share). SCE&G's share of amounts received, net of certain expenses, total $1.095 billion. The purchase agreement provides that SCE&G and Santee Cooper (each according to its pro rata share) would indemnify Citibank for its losses arising from misrepresentations or covenant defaults under the purchase agreement. SCE&G and Santee Cooper also assigned their claims under the WEC bankruptcy process to Citibank, and agreed to use commercially reasonable efforts to cooperate with Citibank and provide reasonable support necessary for its enforcement of those claims. The proceeds received under or arising from the monetization of the Toshiba Settlement were recorded as cash and as a regulatory liability on the accompanying balance sheets, as the net value of the proceeds will be utilized to benefit SCE&G's customers in a manner to be determined by the SCPSC. While this determination is pending, SCE&G has utilized portions of the proceeds to repay maturing commercial paper balances, which short-term borrowings had been incurred primarily for the construction of Unit 2 and Unit 3 prior to the decision to stop their construction. See further discussion in Note 4.

A number of subcontractors and vendors to the Consortium have alleged non-payment by the Consortium for amounts owed for work performed on the Nuclear Project and have filed liens on property in Fairfield County, South Carolina, where Unit 2 and Unit 3 were to be located. SCE&G is contesting the filed liens. Payments under the Toshiba Settlement are subject to reduction if WEC pays creditors holding these liens directly. Under these circumstances, SCE&G and Santee Cooper, each in its pro rata share, would be required to make Citibank whole for the reduction. On January 2, 2018, the purchase agreement among SCE&G, Santee Cooper and Citibank was amended to limit the amount that SCE&G and Santee Cooper could be required to reimburse Citibank for valid subcontractor and vendor liens to $60 million ($33 million for SCE&G's 55% share).

Determination to Stop Construction and Related Regulatory, Political and Legal Developments

The BLRA provides that, in the event of abandonment prior to plant completion, costs incurred, including AFC, and a return on those costs, may be recoverable through rates, if the SCPSC determines that the decision to abandon the Nuclear Project was prudent. Based on the evaluation previously discussed, and in light of Santee Cooper's decision to suspend construction, on July 31, 2017, the Company determined to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means. On July 31, 2017, SCE&G gave WEC a five-day notice of termination of the Interim Assessment Agreement and notified WEC of its determination to stop construction of Unit 2 and Unit 3.

On August 1, 2017, SCE&G senior management provided an allowable ex parte briefing to the SCPSC regarding the Nuclear Project and this decision, and SCE&G also filed a petition with the SCPSC which included its plan of abandonment and certain proposed actions which would mitigate related customer rate increases, including a proposal to return to customers the net value of proceeds received by SCE&G under or arising from the monetization of the Toshiba Settlement. Through this petition, SCE&G had sought recovery of such costs expended on the construction of the Nuclear Project, including certain costs incurred subsequent to SCE&G's last revised rates update, and certain other costs under the abandonment provisions of the BLRA. Subsequently, SCE&G’s management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow for adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew its petition to abandon the project from the SCPSC on August 15, 2017.

In August 2017, special committees of the South Carolina General Assembly, both in the House of Representatives and in the

Senate, began conducting public hearings regarding the decision to abandon the Nuclear Project. Members of SCE&G's senior management, along with representatives from Santee Cooper, the ORS and other interested parties, testified before these committees. Several legislative proposals adverse to SCE&G resulted from the work of these committees and certain adverse proposals have been or are being considered by the General Assembly in 2018. In January 2018, these committees reconvened for the purpose of considering the effects of the proposed merger discussed below on Nuclear Project stakeholders. On January 31, 2018, the South Carolina House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. SCE&G cannot predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

In September 2017, the Company was served with a subpoena issued by the United States Attorney’s Office for the District of South Carolina seeking documents relating to the Nuclear Project. The subpoena requires the Company to produce a broad range of documents related to the project. Also in September 2017, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. In October 2017, the staff of the SEC's Division of Enforcement also issued a subpoena for documents related to an investigation they are conducting related to the Nuclear Project. SCE&G intends to fully cooperate with these investigations. Also in connection with the abandonment of the Nuclear Project, various state or local governmental authorities have attempted and may further attempt to challenge, reverse or revoke one or more previously-approved tax or economic development incentives, benefits or exemptions and may attempt to apply such action retroactively. No assurance can be given as to the timing or outcome of these matters.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the South Carolina General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections. SCE&G estimates that revised rates collections, including collections related to transmission assets expected to be placed into service, currently total approximately $445 million annually, and such amounts accumulated as of December 31, 2017 total approximately $1.9 billion.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed a motion with the SCPSC to amend the Request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. Parties who filed to intervene in the matter or who filed a letter in support of the request by the ORS include the Governor, the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, the SCEUC, certain large industrial customers, and several environmental groups. After conducting a hearing to consider SCE&G's motion, the SCPSC denied the motion on December 20, 2017 and requested that the ORS carry out an inspection, audit and examination of SCE&G's revenue requirements to assist the SCPSC in determining whether SCE&G's present schedule of rates is fair and reasonable and also ordered that a hearing be scheduled to consider the Request. The hearing has not yet been scheduled. SCE&G intends to continue vigorously contesting the Request, but cannot give any assurance as to the timing or outcome of this matter. See also Note 2.

Proposals to Resolve Outstanding Issues

On November 16, 2017, SCE&G announced for public consideration a proposal to resolve outstanding issues relating to the Nuclear Project. Under the proposal, SCE&G electric customers were to receive a 3.5% electric rate reduction, the addition of an existing 540-MW natural gas fired power plant by SCE&G with the acquisition cost borne by SCANA shareholders, and the addition of approximately 100-MW of large scale solar energy by SCE&G. The proposal also provided for the recovery of the nuclear construction costs (net of the proceeds of the Toshiba Settlement not utilized for liquidation of project liens) over 50 years. While SCE&G’s proposal was not formally submitted for regulatory approval, discussions with key stakeholders over the ensuing weeks indicated that SCE&G's proposal would not be sufficient to resolve the outstanding issues.

On January 2, 2018, SCANA entered into the Merger Agreement with Dominion Energy, and on January 12, 2018, SCE&G and Dominion Energy filed the Joint Petition requesting SCPSC approval of the merger or a finding that either the merger is in the public interest or that there is an absence of harm arising from the merger. In this petition, the parties commit to providing an up-front, one time rate credit to SCE&G's electric customers totaling approximately $1.3 billion within 90 days of the merger's closing, providing at least a 5% reduction in customer bills, shortening the amortization period for costs related to the Nuclear Project to 20 years, forgoing recovery of approximately $1.7 billion in costs related to the Nuclear Project, and adding an existing 540-MW natural gas fired power plant by SCE&G with no initial investment borne by customers. No assurance can be given as to the timing or outcome of efforts to consummate the Merger Agreement or to obtain approval of the Joint Petition.

Impairment Considerations

Under the current regulatory construct in South Carolina, pursuant to the BLRA or through other means, the ability of SCE&G to recover costs incurred in connection with Unit 2 and Unit 3, and a reasonable return on them, will be subject to review and approval by the SCPSC. In light of the contentious nature of the reviews by legislative committees and others, the adverse impact that would result if proposed legislation is enacted, and the Request being considered by the SCPSC that could result in the suspension of rates currently being collected under the BLRA, as well as the return of such amounts previously collected, there is significant uncertainty as to SCE&G's ultimate ability to fully recover its costs of Unit 2 and Unit 3 and a return on them from its customers. SCE&G continues to contest the specific challenges described above. However, based on the consideration of those challenges, and particularly in light of SCE&G's proposed solution announced on November 16, 2017 and details in the Joint Petition filed by SCE&G and Dominion Energy with the SCPSC on January 12, 2018, SCE&G has determined that a disallowance of recovery of part of the cost of the abandoned plant is both probable and reasonably estimable under applicable accounting guidance. In addition, SCE&G has determined that full recovery of certain other related costs deferred within regulatory assets is less than probable. As a result, as of December 31, 2017, SCE&G has recognized a pre-tax impairment loss totaling $1.118 billion ($690 million net of tax). With the exception of the $210 million loss recorded in the third quarter of 2017 as explained below, this impairment loss was recorded in the fourth quarter of 2017. A discussion of this impairment loss follows:

- A pre-tax impairment loss was recorded with respect to disallowance of unrecovered nuclear project costs of approximately $670 million. This amount includes $210 million recorded in the third quarter of 2017, which represented costs of approximately $1.2 billion that had been expended on the project, exclusive of transmission costs, but which had not yet been determined to be prudent by the SCPSC in connection with revised rates proceedings under the BLRA, offset by the amount of approximately $1 billion, which amount represents the recovery of the Toshiba Settlement proceeds that are in excess of amounts from that settlement that SCE&G estimated may be necessary to satisfy certain project liens. This impairment loss also includes $180 million, which amount arises from SCE&G's entry into an agreement in the fourth quarter of 2017 to purchase in 2018 an existing 540-MW combined cycle gas generating station along with SCE&G's commitment to regulators and the public that the recovery of the initial capital investment in the facility would not be sought from customers. The remaining $280 million of this impairment loss was recorded after consideration of the regulatory and political developments described above.

- A pre-tax impairment loss was recorded in the aggregate amount of $361 million to write off costs which had been previously deferred, primarily as regulatory assets, in connection with the Nuclear Project. Such regulatory assets included deferred losses on interest rate swaps for which debt will not be issued due to the abandonment of the Nuclear Project, carrying costs on deferred tax assets arising from the capitalization of interest costs for tax purposes, net deferred costs and tax benefits related to foregone domestic production activities deductions (net of uncertain tax positions and credits) taken with respect to the project, and taxes associated with equity AFC.

- Finally, an $87 million pre-tax impairment loss was recorded in order to reduce to estimated fair value the carrying value of nuclear fuel acquired for use in Unit 2 and Unit 3.

With the exception of the $87 million related to nuclear fuel, the above impairment loss reflects impacts similar to those that may have resulted had the proposed solution announced November 16, 2017 been implemented. That proposal is presented by SCE&G as a less-favored alternative to the merger benefits and cost recovery plan in the January 12, 2018 Joint Petition. It is reasonably possible that a change in the estimated impairment loss could occur in the near term. If the merger benefits and cost recovery plan outlined in the Joint Petition is implemented (upon closing of the merger as contemplated in the Merger Agreement), an additional impairment loss and other charges totaling as much as approximately $1.7 billion would be expected to be recorded. This additional impairment loss would result from the write-off of unrecovered Nuclear Project costs of approximately $856 million recorded within regulatory assets and the recording of additional liabilities for customer refunds totaling approximately $1.875 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. If instead the Joint Petition is not approved and the Request by the ORS is approved, and if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, SCE&G may be required to record an additional impairment loss and other charges totaling as much as approximately $4.8 billion. This additional impairment loss would result from the write-off of the remaining unrecovered Nuclear Project costs of $3.976 billion recorded within regulatory assets and the refund of revised rates collections under the BLRA described above of approximately $1.9 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. SCE&G does not currently anticipate that any of the $1.9 billion in revenue previously collected will be subject to refund; however, no assurance can be given as to the outcome of this matter.

Liquidity Considerations

As a result of the decision to stop construction of Unit 2 and Unit 3, downgrades by credit ratings agencies have recently occurred. SCE&G has significant obligations that must be paid within the next 12 months, including long-term debt maturities and capital lease payments of $556 million, short-term borrowings of $252 million, interest payments of approximately $251 million, and future minimum payments for operating leases of $26 million. Working capital requirements, such as those for fuel supply and similar obligations, also arise due to the lag between when such amounts are paid and when related collection of such costs through customer rates occurs.

Management believes as of the date of issuance of these financial statements that it has access to available sources of cash to pay obligations when due over the next 12 months. These sources include committed, long-term lines of credit that expire in December 2020 totaling $1.4 billion. In addition, as of the date of issuance of these financial statements, SCE&G continues to collect in customer rates amounts previously approved under the BLRA, as well as amounts provided for in other orders related to non-BLRA electric and gas rates. However, as further described below, SCANA's credit rating has fallen below investment grade, which has constricted its ability and that of SCE&G to issue commercial paper.

As described above, on January 31, 2018, the South Carolina House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the

BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Such regulatory, legislative or judicial proceedings outside of SCE&G's control may result in the temporary or permanent suspension of the approximately $445 million annually of rates being collected currently under the BLRA, the return of such amounts previously collected of $1.9 billion, or the requirement that SCE&G's share of payments received from the Toshiba Settlement ($1.095 billion) be placed in escrow or be refunded to customers. SCE&G cannot predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

Were the SCPSC to grant the relief sought by the ORS in the Request or grant similar relief resulting from legislative action, and as further discussed above in Impairment Considerations, an additional impairment loss or other charges totaling as much as approximately $4.8 billion may be required. Such an impairment loss or other charges would further stress SCE&G's equity to total capitalization ratio and may result in SCE&G's ratio of equity to total capitalization falling below minimum levels prescribed in credit agreements. In such an event, SCE&G's ability to borrow under its commercial paper programs and credit facilities and its ability to pay future dividends would likely be limited or may trigger events of default under such agreements.

Known and knowable conditions and events when considered in the aggregate as of the date of issuance of these financial statements do not suggest it is probable that SCE&G will not be able to meet obligations as they come due over the next 12 months. However, possible future actions related to rates or refunds could have a material adverse effect on SCE&G's financial condition, liquidity, results of operations and cash flows such that management's conclusion with respect to its ability to pay obligations when due could change.

Claims and Litigation

Following the Company's decision to stop construction of Unit 2 and Unit 3, putative derivative and class action lawsuits have been filed in multiple state circuit courts and federal district court on behalf of customers, shareholders and SCANA (in the case of the derivative shareholder actions), against SCANA, SCE&G, or both, and in certain cases some of their officers and/or directors. The plaintiffs allege various causes of action, including but not limited to waste, breach of fiduciary duty, negligence, unfair trade practices, unjust enrichment, conspiracy, fraud, constructive fraud, misrepresentation and negligent misrepresentation, promissory estoppel, constructive trust, and money had and received, among other causes of action. Plaintiffs generally seek compensatory and consequential damages and statutory treble damages and such further relief as the court deems just and proper. In addition, certain plaintiffs seek a declaration that SCE&G may not charge its customers to reimburse itself for past and continuing costs of the Nuclear

Project. Certain plaintiffs also seek to freeze or appoint a receiver for certain of SCE&G's assets, including all money SCE&G has received under the Toshiba payment guaranty and related settlement agreement and money to be collected from customers for the Nuclear Project. In some cases, plaintiffs seek to enjoin the merger and rescind the Merger Agreement, or to have the Merger Agreement amended to provide more favorable terms for plaintiffs.

A complaint has been filed by Fairfield County against SCE&G making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of the implied duty of good faith and fair dealing, and unfair trade practices related to SCE&G's termination of the FILOT agreement. Plaintiff seeks injunctive relief to prevent SCE&G from terminating the FILOT agreement; actual and consequential damages; treble damages; punitive damages; and attorneys' fees.

The Company has also been served with subpoenas issued by the United States Attorney's Office for the District of South Carolina and the staff of the SEC's Division of Enforcement seeking documents relating to the Nuclear Project. In addition, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee have requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. SCE&G intends to fully cooperate with any such investigations.

On January 26, 2018, the DOR notified the Company that it was initiating an audit of the Company's sales and use tax returns for the periods September 1, 2008 through December 31, 2017. Based on an introductory meeting regarding that audit on February 8, 2018, the Company understands that the DOR's position is that the exemption for sales and use tax for purchases related to the Nuclear Project should not apply because Unit 2 and Unit 3 will not be placed into service and no electricity will be manufactured for sale. The Company intends to vigorously contest the DOR's position.

While SCE&G intends to vigorously contest the lawsuits, claims, and audit positions which have been filed or initiated against it, SCE&G cannot predict the timing or outcome of these matters or others that may arise, and adverse outcomes from some of these matters would not be covered by insurance. As noted above, the various claims for damages do not specify an amount for those damages and the number of plaintiffs that are ultimately certified in the potential class actions lawsuits is unknown. In addition, each of the cases referred to above is in its early stages. For these reasons, SCE&G cannot provide any estimate or range of potential loss for these matters at this time, and no accrual for these potential losses has been included in the financial statements. However, outcomes could have a material adverse effect on SCE&G's results of operations, cash flows and financial condition.

SCE&G is subject to various other claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on SCE&G's results of operations, cash flows or financial condition.

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Unit 1. Price-Anderson provides funds up to $13.4 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 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. Each reactor licensee is liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin and up to $2.33 billion resulting from an event of a non-nuclear origin. The NEIL policies in aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. The NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $22.3 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Unit 1 for property damage and outage costs up to $415 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $2.0 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on SCE&G's results of operations, cash flows and financial position.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on SCE&G's financial condition, results of operations and cash flows. In addition, SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCE&G continually monitors and evaluates its current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G participates in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also has constructed additional pollution control equipment at its coal-fired electric generating plants. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. SCE&G is monitoring the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

On August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule included state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030, and established a phased-in compliance approach beginning in 2022. The rule gave each state from one to three years to issue its SIP, which would ultimately define the specific compliance methodology that would be applied to existing units in that state. On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. As a result of an Executive Order on March 28, 2017, the EPA placed the rule under review and the Court of Appeals agreed to hold the case in abeyance. On October 10, 2017, the Administrator of the EPA signed a notice proposing to repeal the rule on the grounds that it exceeds the EPA's statutory authority. In a separate but related action, the EPA issued an Advance Notice of Proposed Rulemaking on December 18, 2017, to solicit information from the public about a potential future rulemaking to limit greenhouse gas emissions from existing units. SCE&G expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual SO_2 emissions and annual and ozone season NO_X emissions to assist in attaining the ozone and fine particle National Ambient Air Quality Standards. The rule establishes an emissions cap for SO_2 and NO_X and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. The State of South Carolina has chosen to remain in the CSAPR program, even though recent court rulings exempted the state. This allows the state to remain compliant with regional haze standards. Air quality control installations that SCE&G has already completed have positioned it to comply with the existing allowances set by the CSAPR. Any costs incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The MATS rule has been the subject of ongoing litigation even while it remains in effect. Rulings on this litigation are not expected to have an impact on SCE&G due to plant retirements, conversions, and enhancements. SCE&G is in compliance with the MATS rule and expects to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits such that, as a facility's NPDES permit is renewed, any new effluent limitations would be incorporated. The ELG Rule had become effective on January 4, 2016, after which state regulators could modify facility NPDES permits to match more restrictive standards, which would require facilities to retrofit with new wastewater treatment technologies. Compliance dates varied by type of wastewater, and some were based on a facility's five-year permit cycle and thus could range from 2018 to 2023. However, the ELG Rule is under reconsideration by the EPA and has been stayed administratively. The EPA has decided to conduct a new rulemaking that could result in revisions to certain flue gas desulfurization wastewater and bottom ash transport water requirements in the ELG Rule. Accordingly, in September 2017 the EPA finalized a rule that resets compliance dates under the ELG Rule to a range from November 1, 2020 to December 31, 2023. The EPA indicates that the new rulemaking process may take up to three years to complete, such that any revisions to the ELG Rule likely would not be final until the summer of 2020. While SCE&G expects that wastewater treatment technology retrofits will be required at Wateree Station, any costs incurred to comply with the ELG Rule is expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G is conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications to ensure compliance with this rule. Any costs incurred to comply with this rule are expected to be recoverable through rates.

The EPA's final rule for CCR became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's coal-fired generating facilities. SCE&G has already closed or has begun the process of closure of all of its ash storage ponds and has previously recognized AROs for such ash storage ponds under existing requirements. SCE&G has two ponds and two landfills that are governed by the CCR rule. SCE&G does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

In December 2016, the U.S. Congress passed and the President signed legislation that creates a framework for EPA- approved state CCR permit programs. Under this legislation, an approved state CCR permit program functions in lieu of the self-implementing Federal CCR rule. The legislation allows states more flexibility in developing permit programs to implement the environmental criteria in the CCR rule. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. To date, South Carolina has not begun drafting a CCR rule.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2016, the federal government has not accepted any spent fuel from Unit 1, and it remains unclear when the repository may become available. SCE&G has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2019 and will cost an additional $9.9 million, which is accrued in Other within Deferred Credits and Other Liabilities on the balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2017, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $24.6 million and are included in regulatory assets.

Operating Lease Commitments

SCE&G is obligated under various operating leases for land, office space, furniture, equipment, rail cars, and a purchase power agreement. Leases expire at various dates through 2057.

	Rent Expense		
Millions of dollars	**2017**	**2016**	**2015**
SCE&G	$ 11.4	$ 12.1	$ 12.3

	Future Minimum Rental Payments					
Millions of dollars	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
SCE&G	$ 26	$ 23	$ 1	$ 1	—	$ 17

Asset Retirement Obligations

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2017, SCE&G has recorded AROs of approximately $208 million for nuclear plant decommissioning (see Note 1). In addition, SCE&G has recorded AROs of approximately $308 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	2017	2016
Beginning balance	$ 509	$ 476
Liabilities incurred	—	—
Liabilities settled	(9)	(11)
Accretion expense	23	21
Revisions in estimated cash flows	(7)	23
Ending balance	$ 516	$ 509

Revisions in estimated cash flows in 2017 primarily related to ash pond retirement obligations settled and updates in the timing of cash flows as work is completed. Such revisions in 2016 related to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study.

11. AFFILIATED TRANSACTIONS

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. The net of the total purchases and total sales are recorded in Other expenses on the statements of comprehensive income.

Millions of Dollars	2017	2016	2015
Purchases from Canadys Refined Coal, LLC	$ 73.2	$ 64.5	$ 94.2

Sales to Canadys Refined Coal, LLC	72.7	64.1	93.7

Millions of Dollars	2017	2016
Receivable from Canadys Refined Coal, LLC	$ 4.8	$ 4.7
Payable to Canadys Refined Coal, LLC	4.9	4.8

SCE&G purchases all of the electric generation of Williams Station under a unit power sales agreement. Such unit power purchases are included in Purchased power. SCE&G has a payable to GENCO for unit power purchases.

Millions of Dollars	2017	2016
Purchases from GENCO	$ 174.5	$ 193.9
Payable to GENCO	10.6	20.2

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy to serve its retail gas customers and certain electric generation requirements.

SCANA Services, on behalf of itself and its parent company, provides the following services to SCE&G, which are rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative, and retirement benefits. In addition, SCANA Services processes and pays invoices for SCE&G and is reimbursed. Costs for these services, including amounts capitalized. Amounts expensed are recorded in Other operation and maintenance - nonconsolidated affiliate and Other expenses on the statements of comprehensive income (loss).

Millions of Dollars	2017	2016	2015
Purchases from SCANA Energy	$ 127.4	$ 111.5	$ 128.5
Direct and Allocated Costs from SCANA Services	297.7	331.7	295.5

Millions of Dollars	2017	2016
Payable to SCANA Energy	$ 10.0	$ 8.8
Payable to SCANA Services	41.0	62.0

Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in January 2015.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs is described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution, comprised of the local distribution operations of SCE&G, purchases and sells natural gas, primarily at retail and is regulated by the SCPSC.

Management uses operating income (loss) to measure segment profitability for its regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, no allocation is made to segments for interest charges, income tax expense (benefit) or assets other than utility plant. Intersegment revenue and interest income were not significant. Deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plan and non-fixed assets for the segments. Adjustments to Interest Expense, Expenditures for Assets and Deferred Tax Assets include primarily the amounts that are not allocated to the segments. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs, and totals not allocated to other segments.

Disclosure of Reportable Segments

Millions of Dollars	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2017				
External Revenue	$ 2,664	$ 406	—	$ 3,070
Operating Income	(198)	72	—	(126)
Interest Expense	4	—	$ 269	273
Depreciation and Amortization	275	30	—	305
Segment Assets	11,375	869	3,125	15,369
Expenditures for Assets	180	64	654	898

Deferred Tax Assets	2	n/a	(2)	—
2016				
External Revenue	$ 2,619	$ 367	—	$ 2,986
Operating Income	920	56	—	976
Interest Expense	2	—	$ 253	255
Depreciation and Amortization	268	28	—	296
Segment Assets	11,327	825	3,363	15,515
Expenditures for Assets	1,264	78	45	1,387
Deferred Tax Assets	2	n/a	(2)	—
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	837	58	—	895
Interest Expense	2	—	$ 230	232
Depreciation and Amortization	259	28	—	287
Segment Assets	10,274	757	3,151	14,182
Expenditures for Assets	1,080	57	(136)	1,001
Deferred Tax Assets	—	n/a	—	—

13. OTHER INCOME (EXPENSE), NET

Components of other income (expense), net are as follows:

Millions of dollars	2017	2016	2015
Other income	$ 45	$ 30	$ 32
Other expense	(25)	(24)	(31)
Allowance for equity funds used during construction	15	26	25
Other income (expense), net	$ 35	$ 32	$ 26

14. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $254 million and $236 million in 2017 and 2016, respectively (net of capitalized interest of $15 million and $18 million in 2017 and 2016, respectively).

Income taxes paid: $46 million and $286 million in 2017 and 2016, respectively.
Income taxes received: $144 million and $189 million in 2017 and 2016, respectively.

Noncash Investing and Financing Activities:
Accrued construction expenditures: $92 million and $92 million in 2017 and 2016, respectively.
Capital leases expenditures: $8 million and $14 million in 2017 and 2016, respectively.

15. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2017					
Total operating revenues	$ 719	$ 756	$ 856	$ 739	$ 3,070
Operating income (loss)	213	237	114	(690)	(126)
Earnings Available (Loss Attributable) to Common Shareholder	109	123	39	(456)	(185)
2016					
Total operating revenues	$ 717	$ 692	$ 882	$ 695	$ 2,986

Operating income	226	213	350	187	976
Earnings Available to Common Shareholder	113	110	201	89	513

See Note 10 for a discussion of the impairment loss that was booked in the third quarter and the fourth quarter of 2017.

16. SUBSEQUENT EVENT

On January 2, 2018, SCANA, Sedona Corp. and Dominion Energy entered into the Merger Agreement pursuant to which Sedona Corp. (a wholly-owned subsidiary of Dominion Energy) agreed to merge into SCANA in a stock-for-stock transaction in which SCANA shareholders would receive 0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock. The completion of the merger is subject to a variety of closing conditions, including the receipt of approvals from SCANA's shareholders and is also subject to consents and approvals or findings from governmental entities, which may impose conditions that could have an adverse effect on SCE&G or could cause either SCANA or Dominion Energy to abandon the merger. The completion of the merger is also subject to an absence of substantive changes in certain South Carolina laws, including the BLRA, that would reasonably be expected to have an adverse effect on SCANA or its subsidiaries, or if any governmental entity enacts any order or there is any change in law which imposes any material change to the terms, conditions or undertakings set forth in the Joint Petition or any significant changes to the economic value of the Joint Petition. See also Note 10.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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)
1	Balance of Account 219 at Beginning of Preceding Year				(2,770,003)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				169,937
3	Preceding Quarter/Year to Date Changes in Fair Value				(373,199)
4	Total (lines 2 and 3)				(203,262)
5	Balance of Account 219 at End of Preceding Quarter/Year				(2,973,265)
6	Balance of Account 219 at Beginning of Current Year				(2,973,265)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				154,927
8	Current Quarter/Year to Date Changes in Fair Value				(888,990)
9	Total (lines 7 and 8)				(734,063)
10	Balance of Account 219 at End of Current Quarter/Year				(3,707,328)

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	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 117, Line 78) (i)	Total Comprehensive Income (j)
1			(2,770,003)		
2			169,937		
3			(373,199)		
4			(203,262)	512,691,483	512,488,221
5			(2,973,265)		
6			(2,973,265)		
7			154,927		
8			(888,990)		
9			(734,063)	(184,774,492)	(185,508,555)
10			(3,707,328)		

Schedule Page: 122(a)(b) Line No.: 1 Column: e

Lines 1-5 present information for the period 1/1/16 - 12/31/16.
Lines 6-10 present information for the period 1/1/17 - 12/31/17.

Schedule Page: 122(a)(b) Line No.: 1 Column: h

Lines 1-5 present information for the period 1/1/16 - 12/31/16.
Lines 6-10 present information for the period 1/1/17 - 12/31/17.

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2016.

Schedule Page: 122(a)(b) Line No.: 3 Column: e

Reflects amounts recognized in OCI persuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2016 (as applicable).

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2017.

Schedule Page: 122(a)(b) Line No.: 8 Column: e

Reflects amounts recognized in OCI persuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2017 (as applicable).

Schedule Page: 122(a)(b) Line No.: 10 Column: b

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: c

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: d

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: e

Other Comprehensive Income related to deferred employee benefit plan costs.

Schedule Page: 122(a)(b) Line No.: 10 Column: f

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: g

Not applicable for respondent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	10,764,720,248	9,253,597,906
4	Property Under Capital Leases	22,903,455	20,855,653
5	Plant Purchased or Sold		
6	Completed Construction not Classified	635,222,619	609,999,513
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	11,422,846,322	9,884,453,072
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	345,622,588	332,376,466
12	Acquisition Adjustments	31,597,076	31,360,826
13	Total Utility Plant (8 thru 12)	11,800,065,986	10,248,190,364
14	Accum Prov for Depr, Amort, & Depl	4,394,083,931	3,794,643,075
15	Net Utility Plant (13 less 14)	7,405,982,055	6,453,547,289
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,212,822,667	3,721,922,976
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	173,757,194	65,336,226
22	Total In Service (18 thru 21)	4,386,579,861	3,787,259,202
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	Amort of Plant Acquisition Adj	7,504,070	7,383,873
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,394,083,931	3,794,643,075

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,146,889,407				364,232,935	3
205,395				1,842,407	4
					5
23,783,856				1,439,250	6
					7
1,170,878,658				367,514,592	8
					9
					10
11,147,503				2,098,619	11
236,250					12
1,182,262,411				369,613,211	13
436,256,150				163,184,706	14
746,006,261				206,428,505	15
					16
					17
425,182,129				65,717,562	18
					19
					20
10,953,824				97,467,144	21
436,135,953				163,184,706	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
120,197					32
436,256,150				163,184,706	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	2,654,627	7,400,617
3	Nuclear Materials	137,918,081	69,941,487
4	Allowance for Funds Used during Construction	3,605,617	1,764,067
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	144,178,325	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	72,615,225	159,044,092
9	In Reactor (120.3)	223,723,883	77,577,766
10	SUBTOTAL (Total 8 & 9)	296,339,108	
11	Spent Nuclear Fuel (120.4)	673,993,828	79,454,828
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	843,261,889	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	271,249,372	
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	10,055,244		2
	143,739,063	64,120,505	3
	5,249,784	119,900	4
			5
		64,240,405	6
			7
	170,206,001	61,453,316	8
	85,252,217	216,049,432	9
		277,502,748	10
		753,448,656	11
			12
-44,074,146		887,336,035	13
		207,855,774	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 2 Column: e

Reflects the transfer of fuel balances for Units 2 & 3 from In-Process to In-Stock due to project abandonment. Also, reflects the transfer of fuel balances from Batch 26 In-Process into Batch 26 In-Stock.

Schedule Page: 202 Line No.: 3 Column: e

Reflects the transfer of fuel balances for Units 2 & 3 from In-Process to In-Stock due to project abandonment. Also, reflects the transfer of fuel balances from Batch 26 In-Process into Batch 26 In-Stock.

Schedule Page: 202 Line No.: 4 Column: e

Reflects the transfer of fuel balances for Units 2 & 3 from In-Process to In-Stock due to project abandonment. Also, reflects the transfer of fuel balances from Batch 26 In-Process to Batch 26 In-Stock.

Schedule Page: 202 Line No.: 8 Column: e

To record an impairment of $50,879,634 for Unit 2 and $35,951,211 for Unit 3 to reduce to estimated fair value the carrying value of fuel acquired for use in Units 2 and 3 due to project abandonment.

Also, reflects the transfer of fuel balances from Batch 26 In-Process to Batch 26 In-Stock and then to Batch 26 In-Reactor.

Schedule Page: 202 Line No.: 9 Column: e

Reflects the transfer of fuel balances from Batch 23 In-Reactor to Batch 26 Spent Fuel.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	14,989	
3	(302) Franchises and Consents	13,208,505	
4	(303) Miscellaneous Intangible Plant	79,422,081	6,903,404
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	92,645,575	6,903,404
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,560,651	13,434
9	(311) Structures and Improvements	258,443,092	4,159,968
10	(312) Boiler Plant Equipment	1,047,502,846	20,498,890
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	436,743,492	1,962,206
13	(315) Accessory Electric Equipment	88,969,672	1,151,080
14	(316) Misc. Power Plant Equipment	31,085,163	2,132,297
15	(317) Asset Retirement Costs for Steam Production	-2,488,730	-8,569,605
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,873,816,186	21,348,270
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	880,612	
19	(321) Structures and Improvements	305,981,573	24,835,247
20	(322) Reactor Plant Equipment	514,526,270	98,569,727
21	(323) Turbogenerator Units	115,454,988	183,464
22	(324) Accessory Electric Equipment	114,595,540	773,097
23	(325) Misc. Power Plant Equipment	155,867,438	7,671,018
24	(326) Asset Retirement Costs for Nuclear Production	22,893,826	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,230,200,247	132,032,553
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	29,438,776	46,104
28	(331) Structures and Improvements	49,724,675	132,409
29	(332) Reservoirs, Dams, and Waterways	444,238,887	157,851
30	(333) Water Wheels, Turbines, and Generators	86,968,318	314,594
31	(334) Accessory Electric Equipment	24,332,985	4,629,818
32	(335) Misc. Power PLant Equipment	10,453,769	652,811
33	(336) Roads, Railroads, and Bridges	1,817,517	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	646,974,927	5,933,587
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,918,325	
38	(341) Structures and Improvements	41,733,150	83,006
39	(342) Fuel Holders, Products, and Accessories	7,409,823	185,436
40	(343) Prime Movers	580,889,733	1,458,567
41	(344) Generators	93,560,175	408,047
42	(345) Accessory Electric Equipment	63,589,929	506,365
43	(346) Misc. Power Plant Equipment	1,957,625	132,782
44	(347) Asset Retirement Costs for Other Production	-5,340,517	-752,545
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	786,718,243	2,021,658
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,537,709,603	161,336,068

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	84,256,326	13,012,092
49	(352) Structures and Improvements	6,100,292	5,488
50	(353) Station Equipment	467,000,025	127,243,632
51	(354) Towers and Fixtures	5,356,060	
52	(355) Poles and Fixtures	387,946,967	136,341,345
53	(356) Overhead Conductors and Devices	219,018,069	86,512,736
54	(357) Underground Conduit	20,544,815	
55	(358) Underground Conductors and Devices	57,232,914	
56	(359) Roads and Trails	73,767	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,247,529,235	363,115,293
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	57,919,821	494,445
61	(361) Structures and Improvements	4,901,028	-2,244,187
62	(362) Station Equipment	394,176,400	12,361,904
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	458,402,181	16,054,348
65	(365) Overhead Conductors and Devices	493,731,400	18,860,176
66	(366) Underground Conduit	150,402,094	5,229,160
67	(367) Underground Conductors and Devices	446,220,664	21,309,156
68	(368) Line Transformers	467,837,832	16,056,577
69	(369) Services	283,679,173	7,468,744
70	(370) Meters	112,006,995	7,496,028
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	313,739,414	16,664,836
74	(374) Asset Retirement Costs for Distribution Plant	221,056	-114,572
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,183,238,058	119,636,615
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	8,375,756	
87	(390) Structures and Improvements	108,979,774	483,518
88	(391) Office Furniture and Equipment	13,713,915	294,793
89	(392) Transportation Equipment	18,425,794	362,672
90	(393) Stores Equipment	247,823	
91	(394) Tools, Shop and Garage Equipment	3,812,255	157,457
92	(395) Laboratory Equipment	6,327,228	170,350
93	(396) Power Operated Equipment	57,449,156	4,300,168
94	(397) Communication Equipment	7,411,905	345,524
95	(398) Miscellaneous Equipment	6,312,028	281,161
96	SUBTOTAL (Enter Total of lines 86 thru 95)	231,055,634	6,395,643
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	231,055,634	6,395,643
100	TOTAL (Accounts 101 and 106)	9,292,178,105	657,387,023
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)	9,292,178,105	657,387,023

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			14,989		2
			13,208,505		3
12,183,341		-8,809,097	65,333,047		4
12,183,341		-8,809,097	78,556,541		5
					6
					7
21,010			13,553,075		8
1,463,965			261,139,095		9
5,788,031			1,062,213,705		10
					11
8,720,692			429,985,006		12
238,746			89,882,006		13
565,646			32,651,814		14
-8,358,435			-2,699,900		15
8,439,655			1,886,724,801		16
					17
			880,612		18
1,498,127		-1,331	329,317,362		19
2,278,342			610,817,655		20
883,667			114,754,785		21
405,641		1,331	114,964,327		22
1,224,912		8,809,097	171,122,641		23
			22,893,826		24
6,290,689		8,809,097	1,364,751,208		25
					26
		-96	29,484,784		27
15,251		14,189	49,856,022		28
			444,396,738		29
58,569			87,224,343		30
193,855			28,768,948		31
116,831			10,989,749		32
			1,817,517		33
					34
384,506		14,093	652,538,101		35
					36
			2,918,325		37
12,995			41,803,161		38
3,631		-1,997	7,589,631		39
761,333		-67	581,586,900		40
324,583		67	93,643,706		41
22,700			64,073,594		42
8,047		1,997	2,084,357		43
			-6,093,062		44
1,133,289			787,606,612		45
16,248,139		8,823,190	4,691,620,722		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
6,320		-620,167	96,641,931		48
140			6,105,640		49
2,589,216		556,144	592,210,585		50
192,311			5,163,749		51
2,281,307	4,408	105,812	522,117,225		52
1,434,552	-4,408	-113,187	303,978,658		53
95,700		-900,000	19,549,115		54
433,276		900,000	57,699,638		55
			73,767		56
					57
7,032,822		-71,398	1,603,540,308		58
					59
		620,168	59,034,434		60
1,876			2,654,965		61
1,912,243		-548,769	404,077,292		62
					63
2,918,502		-423	471,537,604		64
2,309,477		-29,603	510,252,496		65
88,179			155,543,075		66
1,736,535		29,975	465,823,260		67
2,586,929		-430	481,307,050		68
193,956			290,953,961		69
1,811,468			117,691,555		70
					71
					72
2,559,154		481	327,845,577		73
			106,484		74
16,118,319		71,399	3,286,827,753		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			8,375,756		86
179,940		4,316	109,287,668		87
547,976		-17,908	13,442,824		88
744,719		-14,228	18,029,519		89
130,024			117,799		90
225,435			3,744,277		91
268,082			6,229,496		92
9,767,576		14,228	51,995,976		93
1,576,099			6,181,330		94
90,086			6,503,103		95
13,529,937		-13,592	223,907,748		96
					97
					98
13,529,937		-13,592	223,907,748		99
65,112,558		502	9,884,453,072		100
					101
					102
					103
65,112,558		502	9,884,453,072		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
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40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Schedule Page: 213 Line No.: 1 Column: a

The Company charges a rental fee to Spirit Communications for communication tower site ground leases.

SCANA Services, Inc.(an associated company) utilizes certain assets, including both office space and equipment, that are owned by SCE&G and classified as electric, gas and common utility plant on the Company's books. SCE&G charges SCANA Services a rental fee for such asset usage.

See Transactions with Associated Companies Schedule on page 429 for additional details.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
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30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Steam Production	
2	Water 1 480v Motor Control Center and 4160v Coal Handling Switchgear	4,319,716
3	Cope Dual Fuel Firing Systems	3,027,114
4	McMeekin 1 LP Turbine Rotor Buckets	2,050,626
5	Cope SCR Catalyst	1,317,807
6	Wateree Unit 1 Baghouse Fabric Bags	1,139,822
7	McMeekin High Energy Piping	949,356
8	Cope Coal Bunker Silos	866,251
9	McMeekin 1 High Energy Piping	692,843
10	McMeekin 1 Generator Field Insulation	679,226
11	McMeekin 1 ID Fan VFD Controllers	562,307
12	McMeekin 1 HP/IP Turbine Buckets	556,839
13	McMeekin 1 Generator Exciter Volt Regulator	403,649
14	Urquhart Wateree Treatment 2017	383,107
15	Urquhart 2 Motor Control Centers	340,236
16	Urquhart Waste Water System	318,754
17	Urquhart1 Motor Control Centers	318,065
18	Wateree Gearboxes 2017	250,657
19	Minor Steam Production	1,881,786
20	Nuclear Production	
21	VCS #1 Offsite Water System (OWS)	29,249,874
22	VCS #1 Security Incident and Event Monitor Project	5,768,590
23	VCS #1 Open Phase Detection System	5,475,192
24	VCS #1 Service Water Chemical Treatment Equipment	3,936,814
25	VCS #1 FLEX Alternate Feedwater Suction Source	3,876,765
26	VCS #1 B Loop Auxiliary Crane Replacement	2,138,017
27	VCS #1 Simplex Equipment Replacement	2,081,140
28	VCS #1 License Renewal Project	2,053,966
29	VCS #1 Protected Area Bullet Resistant Enclosures	1,809,442
30	VCS #1 Safety Related Bravo Chiller Replacement	1,659,250
31	VCS #1 Safety Related Power Operated Relief Valves Controls	1,119,202
32	VCS #1 Replace Reactor Makeup Water Storage Tank Heat Tracing	1,054,425
33	VCS #1 Diesel Generators Exciter Replacement	1,033,391
34	VCS #1 Cable Replacement	792,992
35	VCS #1 Power Operated Relief Valves Tailpipe Equalizing Line	682,638
36	VCS #1 Service Building Roof Replacement	612,097
37	VCS #1 SAS HVAC	512,573
38	VCS #1 EP CDA Cyber Security Remediation	473,085
39	VCS #1 External Flood Mitigation	429,657
40	VCS #1 Portal Enterprise Buildings Integrator Scanners	424,198
41	VCS #1 Physical Protection Fencing	366,005
42	VCS #1 Penstock Piping Project	350,988
43	TOTAL	332,376,466

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	VCS #1 Diesel Generator Heat Exchanger Tube Bundles	318,107
2	VCS #1 Spent Fuel Storage Casks	292,508
3	Minor Nuclear Production	1,463,535
4	Hydro Production	
5	Fairfield Pump Storage 480v Motor Control Center and 13.8kV Switchgear	1,758,272
6	Minor Hydro Production	409,796
7	Other Production	
8	Hagood #5 Stage 1 High Pressure Turbine Nozzle	301,696
9	Minor Other Production	1,061,329
10	Overhead Transmission Lines	
11	Yemassee-Burton 230 (115)kV	14,223,936
12	Thomas Isl.-Jack Primus 115kV R/W	4,320,722
13	Saluda Hydro Harbison 115kV Reterminate to Lake Murray	1,656,851
14	Faber Place - Charlotte St. 115kV	1,504,686
15	Urquhart-Graniteville Rebuild 230kV	1,226,414
16	Faber Place-Hagood 115kV Line #2	1,027,942
17	Burton-St. Helena Island 115kV G-Line	904,331
18	Williams-Faber Place Replace Strs	549,750
19	Queensboro SW Station - Terminate Lines	500,171
20	Summerville-Pepperhill 230kV Line	359,796
21	Saluda Hydro: Reconnect Harbison & McMeekin #2	348,909
22	Williams-Cainhoy Rebuild SPDC B795	346,473
23	Yemassee-McIntosh 115kV: Thermal Uprate	330,790
24	Jushi 115kV Fold-In: Columbia Industrial Park-Hopkins	310,365
25	Victory Gardens-Circle Dr. 115kV	276,139
26	Hopkins 230-115kV Sub: Fold-In	261,286
27	Minor Overhead Transmission Lines	1,566,096
28	Overhead Transmission Lines NND	
29	St George-Summerville #1 230kV	31,960,039
30	Gaston - Orangeburg 230 kV	26,232,495
31	Dixiana - Gaston 230kV	8,364,966
32	Saluda Rapids - Dunbar Rd. 230kV	6,493,739
33	Dunbar Rd. - Dixiana 230 kV	2,973,715
34	Arrowwood - Saluda Rapids 230Kv	2,928,249
35	Minor Overhead Transmission Lines NND	13,250
36	Overhead Transmission Lines Non BLRA	
37	Dunbar Rd.-Orangeburg 115kV	18,487,025
38	St George-Summerville 230kV Line #2	15,190,010
39	Dunbar Rd.-Orangeburg 115kV	1,025,336
40	Minor Overhead Transmission Lines Non BLRA	
41	Transmission Substation	
42	Queensboro Transmission Sub #2057	4,499,413
43	TOTAL	332,376,466

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Hopkins-Add Autobank, Bus Tie Breakers, 2 Terminals	4,141,987
2	Urquhart Add Switch House	3,740,231
3	Orangeburg East Sub: 2 230kV Terms	3,097,654
4	Blackville Trans-Add 115-12kV Bank	1,475,702
5	Burton Substation-Add 115kV Term.	1,395,699
6	Wateree Station 230kV Sub #2531	1,287,446
7	Urquhart Station Sub #2501	1,285,805
8	Faber Place Sub: Add 115kV Terminal	1,070,186
9	Saluda Hydro Sub: Ugd 115 Term to SRT	834,365
10	Cainhoy Trans: add 115-23kV Dist.	681,637
11	Edenwood Sub-Replace 4 Breakers	587,182
12	Calhoun County Sub-Relocate SCADA Pole	569,900
13	Summerville 230kV Sub. #2071	528,016
14	SRP Series Reactors	509,451
15	Rader Sub: Replace Failed Transformer	405,832
16	Blackville Trans: Add Reverse Flow	254,407
17	Minor Transmission Substation	1,941,162
18	Transmission Substation NND	
19	Saluda Hydro Sub: Upgrade 115kV Bus	865,954
20	Summerville 230kV Sub. #2071	349,529
21	Minor Transmission Substation NND	149,439
22	Distribution Substation	
23	Jack Primus 115-23kV Sub: Construct	2,445,555
24	Sweetwater 115-12kV Sub: Incr. Capc	1,652,517
25	Ridgeville 115-46kV-Inst. 22.4MVA	1,367,323
26	Sewee Sub. No. 807- Construct	1,176,134
27	Estill Southside Add Bank & 1 Breaker	967,229
28	Upgrade Various RTUs at Solar Impac	316,579
29	Minor Distribution Substation	1,059,719
30	Customer Substation	
31	Clemson W.T. Sub: Construct 115/23	889,356
32	Kronotex Sub: Add 115-13.8kV Transformer	251,416
33	Minor Customer Substation	556,951
34	Overhead Distribution Lines	
35	Springdale 17412 Reconductor	436,264
36	Old Eastover Hwy Reconductor	416,488
37	Buena Vista Phase 1	403,359
38	Western District SCADA Switch 2017	355,557
39	2017 Lexington SCADA	342,518
40	Metro SCADA Switches 2017	327,854
41	2017 SCADA New Installs	319,371
42	Southern District SCADA 2017	302,053
43	TOTAL	332,376,466

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	2017 SCADA Switches North Charleston	287,851
2	Belmont Circuit 810 - Corrections	258,646
3	Minor Overhead Distribution Lines	2,599,737
4	U/G Distribution Lines	
5	Network Protector Upgrades	439,976
6	Minor U/G Distribution Lines	3,179,810
7	Land and Structures	
8	Install System Protection Training Facility	1,162,887
9	Minor Land and Structures	
10	Transportation & POE	
11	Minor Transportation & POE	34,043
12	Office Furniture and Equipment	
13	CIP5 Network Upgrade	494,418
14	Minor Office Furniture and Equipment	248,516
15	Communication Equipment	
16	Replace Entire Radio System	4,788,647
17	Minor Communication Equipment	28,763
18	Tools & Test Equipment	
19	Admin WO AFUDC Adjustments	-4,067,460
20	Minor Tools & Test Equipment	168,028
21	Intangible Plant	
22	VCS - NFPA 805 Software	17,878,716
23	CHAMPS Replacement	14,911,554
24	Seismic PRA Project	8,665,522
25	Work Management System (WMS)	2,208,911
26	OSI PI Software	467,542
27	Phase II-CIS Updates for DER Progrms	417,455
28	Minor Intangible Plant	717,895
29	Payroll Overheads and Adjustments	-719,417
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	332,376,466

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 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), 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.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year	3,592,591,410	3,592,591,410		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	228,210,430	228,210,430		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,792,463	2,792,463		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-9,425,077	-9,425,077		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	221,577,816	221,577,816		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	49,204,240	49,204,240		
13	Cost of Removal	40,796,030	40,796,030		
14	Salvage (Credit)	3,583,248	3,583,248		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	86,417,022	86,417,022		
16	Other Debit or Cr. Items (Describe, details in footnote):	-5,829,228	-5,829,228		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,721,922,976	3,721,922,976		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	831,258,745	831,258,745		
21	Nuclear Production	608,125,468	608,125,468		
22	Hydraulic Production-Conventional	303,882,423	303,882,423		
23	Hydraulic Production-Pumped Storage	76,372,924	76,372,924		
24	Other Production	420,952,493	420,952,493		
25	Transmission	362,089,771	362,089,771		
26	Distribution	1,029,790,160	1,029,790,160		
27	Regional Transmission and Market Operation				
28	General	89,450,992	89,450,992		
29	TOTAL (Enter Total of lines 20 thru 28)	3,721,922,976	3,721,922,976		

Schedule Page: 219 Line No.: 8 Column: c

Depreciation of Asset Retirement Costs, Distributed Energy Resources property and Cyber Security property recorded as a regulatory asset.

Schedule Page: 219 Line No.: 12 Column: c

Retirements per Page 207, Line 100 column (d)	$ 65,112,558
Less: Intangible Plant per Page 205, Line 5 column (d)	(12,183,341)
Capital Lease Asset Reductions Recorded in Accordance with USoA General Instruction No. 20 shown as Plant Retirements	(3,724,977)
Total	$ 49,204,240

Schedule Page: 219 Line No.: 16 Column: c

ARC retirements reclassified to Regulatory Assets	($ 8,380,028)
Loss on Disposal on Vehicles	23,770
Book Cost of Land Retired	27,330
Transfers and Adjustments	2,499,700
Total	($ 5,829,228)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	APOG, LLC			250
2	Canadys Refined Coal, LLC			718,021
3	Louisa Refined Coal, LLC			244,529
4	Brandon Shores Coaltech, LLC			265,597
5	Brunner Island Refined Coal, LLC			1,627,983
6	Cope Refined Coal, LLC			
7				
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9				
10				
11				
12				
13				
14				
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33				
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36				
37				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	2,856,380

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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 form investments, including such revenues form 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 difference 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

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)	Line No.
		250		1
-2,055,672		349,082		2
-1,490,347		200,100		3
-887,231		280,160		4
-1,177,867		816,718		5
			1,096,369	6
				7
				8
				9
				10
				11
				12
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				34
				35
				36
				37
				38
				39
				40
				41
-5,611,117		1,646,310	1,096,369	42

Schedule Page: 224 Line No.: 2 Column: g

Amount includes additional investments made during the year of $1,686,733.

Schedule Page: 224 Line No.: 3 Column: g

Amount includes additional investments made during the year of $1,445,918.

Schedule Page: 224 Line No.: 4 Column: g

Amount includes additional investments made during the year of $901,794.

Schedule Page: 224 Line No.: 5 Column: g

Amount includes additional investments made during the year of $366,602.

Schedule Page: 224 Line No.: 6 Column: h

In 2012, SCE&G sold its 10% interest in Cope Refined Coal, LLC and is being paid for such interest over future periods. This amount reflects such payment received in 2017 and has been recorded in Account 421 - Miscellaneous Nonoperating Income.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	46,289,912	49,154,758	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
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)	96,230,379	99,325,340	Electric
8	Transmission Plant (Estimated)	8,440,866	8,722,551	Electric
9	Distribution Plant (Estimated)	29,483,037	31,006,665	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	367,869	510,167	Fleet
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	134,522,151	139,564,723	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	180,812,063	188,719,481	

Schedule Page: 227   Line No.: 11   Column: c

Fleet materials and supplies inventory

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	281,034.40	640,580	73,470.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
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	4,498.40	7,111		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	276,536.00	633,469	73,470.00	
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	659.50		659.50	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	659.50			
40	Balance-End of Year			659.50	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
45,625.00		45,625.00		1,186,250.00		1,632,004.40	640,580	1
								2
								3
				45,625.00		45,625.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						4,498.40	7,111	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
45,625.00		45,625.00		1,231,875.00		1,673,131.00	633,469	29
								30
								31
								32
								33
								34
								35
659.50		659.50		32,315.50		34,953.50		36
				1,319.00		1,319.00		37
								38
				659.50		1,319.00		39
659.50		659.50		32,975.00		34,953.50		40
								41
								42
								43
								44
								45
								46

Schedule Page: 228 Line No.: 4 Column: j

Vintage 2047 allowances allocated by the EPA for the SO2 Acid Rain Program.

Schedule Page: 228 Line No.: 18 Column: m

Allowances Inventory charged to account 509 - Allowances does not agree to page 320, line 12 column (b) due to the gain on sale of CSAPR NOx Ozone Season emission allowances. SCE&G is no longer required to participate in the CSAPR NOx Ozone Season Progam. The emission allowances sold were allocated to SCE&G by the EPA at no cost.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	22,944.70		8,817.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
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	8,044.30			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	14,900.40		8,817.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		373,608		
34	Gains		373,608		
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						31,761.70		1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						8,044.30		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
						23,717.40		29
								30
								31
								32
							373,608	33
							373,608	34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 33 Column: c

Gain on sale of CSAPR Nox Ozone Season emission allowances.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
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14						
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17						
18						
19						
20	TOTAL					

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 Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant:					
22						
23	Unrecovered Plant related to the					
24	retirement of Canadys Unit No. 1					
25	SCPSC authorization received					
26	12/2012. (Docket No. 2012-218-E,					
27	Order 2012-951) Amortization					
28	over approximately 14 years					
29	beginning 1/2013.	19,761,879		407	1,607,593	11,723,914
30						
31	Unrecovered Plant related to the					
32	retirement of Canadys Unit No. 2					
33	and Unit No. 3. SCPSC					
34	authorization received 9/2013.					
35	(Docket No. 2013-276-E, Order					
36	2013-649) Amortization over					
37	approximately 12 years beginning					
38	1/2014.	143,194,304	2,138,193	407	12,270,624	93,089,256
39						
40	Unrecovered Plant associated with					
41	early retirement of coal					
42	equipment at Urquhart Unit No. 3.	557,755				557,755
43						
44	Unrecovered Plant associated with					
45	early retirement of coal					
46	equipment at McMeekin Station.	1,427,729				1,427,729
47						
48						
49	TOTAL	164,941,667	2,138,193		13,878,217	106,798,654

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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					
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21	**Generation Studies**				
22					
23	20160208001 Facilities Study	458	408.1/561.7/926		
24	20160810001 Facilities Study	612	408.1/561.7/926	67,500	253
25	20160810001 System Impact Study	140	408.1/561.7/926		
26	20170713001 System Impact Study			10,000	253
27	20171107001 System Impact Study			85,600	253
28	20171109002 System Impact Study			85,600	253
29	20170814002 System Impact Study			85,600	253
30	20170814003 System Impact Study			85,600	253
31	20170814001 System Impact Study			85,600	253
32	20171109001 System Impact Study			85,600	253
33	20171101001 System Impact Study			85,600	253
34	20171013002 Feasibility Study			20,000	253
35	20171013001 System Impact Study			85,600	253
36	20171121001 System Impact Study			85,600	253
37	20170206001 System Impact Study	2,589	408.1/561.7/926	29,825	253
38	20170206001 Facilities Study	585	408.1/561.7/926		
39	20170405001 Feasibility Study			10,000	253
40	20170405001 System Impact Study	3,648	408.1/561.7/926	40,000	253

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
4					
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12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20170405001 Facilities Study	701	408.1/561.7/926	34,900	253
23	20170428001 System Impact Study	5,508	408.1/561.7/926	50,000	253
24	20170421001 System Impact Study	5,881	408.1/561.7/926	50,000	253
25	20170428001 Feasibility Study			35,000	253
26	20170421001 Feasibility Study			35,000	253
27	20170621001 System Impact Study			85,000	253
28	20170727003 System Impact Study			85,000	253
29	20170906001 System Impact Study			84,970	253
30	20171006003 System Impact Study			85,000	253
31	20171006002 System Impact Study			85,000	253
32	20171006001 System Impact Study			85,000	253
33	20170405002 System Impact Study	3,928	408.1/561.7/926	84,900	253
34	20170405002 Facilities Study	761	408.1/561.7/926		
35	20170720002 System Impact Study			84,900	253
36	20170720003 System Impact Study			84,900	253
37	20151013003 System Impact Study			2,250	253
38	20171031001 System Impact Study			80,200	253
39	20171130001 System Impact Study			86,520	253
40	20170727002 System Impact Study			85,000	253

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
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11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20170727001 System Impact Study	522	408.1/561.7/926	84,500	253
23	20170802001 System Impact Study			84,440	253
24	20160811001 Facilities Study	1,191	408.1/561.7/926		
25	20170602001 System Impact Study	2,227	408.1/561.7/926	68,900	253
26	20170911002 System Impact Study			72,206	253
27	20171016001 System Impact Study			28,007	253
28	20170427002 System Impact Study	2,162	408.1/561.7/926	30,000	253
29	20170427003 System Impact Study	2,174	408.1/561.7/926	30,000	253
30	20171027001 Feasibility Study			10,000	253
31	20171018008 System Impact Study			20,000	253
32	20171018009 System Impact Study			20,000	253
33	20171018010 System Impact Study			110,000	253
34	20171018011 System Impact Study			20,000	253
35	20171018001 Feasibility Study			20,000	253
36	20171018002 Feasibility Study			20,000	253
37	20171018003 Feasibility Study			20,000	253
38	20171018004 Feasibility Study			20,000	253
39	20171018005 Feasibility Study			20,000	253
40	20171018005 System Impact Study			90,000	253

Transmission Service and Generation Interconnection Study Costs (continued)

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					
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17					
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19					
20					
21	**Generation Studies**				
22	20171018006 Feasibility Study			20,000	253
23	20171018007 Feasibilitiy Study			20,000	253
24	20171113002 Feasibility Study			20,000	253
25	20171113001 Feasibility Study			20,000	253
26	20170911001 Feasibility Study			10,000	253
27	20171113003 Feasibility Study			20,000	253
28	20170308001 System Impact Study	3,990	408.1/561.7/926	30,000	253
29	20170825001 System Impact Study			80,000	253
30	20160927001 System Impact Study	2,271	408.1/561.7/926		
31	20161027002 System Impact Study	1,261	408.1/561.7/926		
32	20161027002 Facilities Study	1,011	408.1/561.7/926		
33	20171122001 System Impact Study	1,261	408.1/561.7/926		
34	20170119001 System Impact Study	4,982	408.1/561.7/926	17,200	253
35	20161109001 Supplemental Review	325	408.1/561.7/926	2,250	253
36	20170117001 System Impact Study	2,077	408.1/561.7/926	16,000	253
37	20170117001 Facilities Study	1,113	408.1/561.7/926		
38	20170117002 System Impact Study	1,872	408.1/561.7/926	30,000	253
39	20170117002 Facilities Study	1,320	408.1/561.7/926		
40	20170117003 System Impact Study	2,316	408.1/561.7/926	28,000	253

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
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10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20170117003 Facilities Study	1,235	408.1/561.7/926		
23	20160927001 Facilities Study	702	408.1/561.7/926		
24	20170215001 Supplemental Review	186	408.1/561.7/926	2,250	253
25	20170728001 System Impact Study			70,000	253
26	20170801001 System Impact Study			30,000	253
27	20170803001 Facilities Study			40,000	253
28	20170809001 System Impact Study	3,212	408.1/561.7/926	15,010	253
29	20171116002 System Impact Study			77,690	253
30	20171101002 System Impact Study			15,140	253
31	20171116001 System Impact Study			15,400	253
32	20171122001 System Impact Study			27,600	253
33	20171221001 System Impact Study			16,000	253
34	20170130001 System Impact Study	1,258	408.1/561.7/926	18,750	253
35	20170130001 Facilities Study	965	408.1/561.7/926		
36	20170511001 Supplemental Review	1,036	408.1/561.7/926	2,250	253
37	20161006001 Facilities Study	699	408.1/561.7/926		
38	20161006001 System Impact Study	3,080	408.1/561.7/926		
39	20160803001 Facilities Study	731	408.1/561.7/926	76,050	253
40	20170531001 System Impact Study	7,939	408.1/561.7/926	82,500	253

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20170403001 System Impact Study	3,157	408.1/561.7/926	7,500	253
23	20160912001 System Impact Study	1,121	408.1/561.7/926	10,996	253
24	20170123001 System Impact Study	6,529	408.1/561.7/926	85,000	253
25	20170307001 System Impact Study	2,629	408.1/561.7/926	85,000	253
26	20170307001 Facilities Study	835	408.1/561.7/926		
27	20171017001 System Impact Study			85,000	253
28					
29					
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39					
40					

Schedule Page: 231 Line No.: 2 Column: a

No Transmission Studies for reporting period.

Schedule Page: 231 Line No.: 22 Column: d

Column (d) represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to expense as the actual charges are incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Income Taxes	293,055,200	18,609,300	282/426.5	285,162,500	26,502,000
2	Columbia & Charleston Franchise	17,486,487		407	4,183,226	13,303,261
3	Gas Water Heater Rebate Program (2012-2022)	5,299,190	4,683,830	912	4,129,292	5,853,728
4	Decommissioning Asset Ret. Obligation	49,234,995	36,043,575	128	16,850,936	68,427,634
5	MGP Environmental Remediation	25,696,765	40,602,907	735	41,655,573	24,644,099
6	Deferred ARO Accretion & Depreciation Costs	338,737,297	14,158,932	230	26,600,265	326,295,964
7	Interest Rate Derivatives	611,440,556	21,538,762		186,567,064	446,412,254
8	Deferred Employee Benefit Plan Costs-Gas (ASC 715)	30,086,833	30,122,424		30,105,700	30,103,557
9	Deferred Employee Benefit Plan Costs-Elec (ASC 715)	211,676,663	179,663,494		211,830,617	179,509,540
10	Gas Customer Awareness Program (11/2012-10/2019)	213,577		913	180,227	33,350
11	Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	4,690,151		530	183,816	4,506,335
12	Deferred Capacity Charges (7/2010-7/2020)	1,048,334		555	296,000	752,334
13	Deferred Capacity Charges	2,134,511				2,134,511
14	Electric Demand Side Management	64,363,758	22,933,215	254/908	21,050,151	66,246,822
15	Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	7,943,599		555	282,660	7,660,939
16	Economic Development Grants (10/2009-5/2032)	14,735,743	500,000	921	1,911,564	13,324,179
17	Major Maintenance Accrual and Interest	11,148,889	16,107,751		8,135,536	19,121,104
18	Deferred Pension Cost - Gas (11/2013-1/2027)	10,366,605		926	1,029,508	9,337,097
19	Deferred Pension Cost - Electric (1/2013-12/2042)	54,701,592		926	1,987,836	52,713,756
20	Environmental Compliance Studies (7/2010 - 7/2020)	335,690		506	94,784	240,906
21	Deferred Pollution Control Costs -					
22	Wateree (1/2013-9/2040)	25,155,956		407.3	1,061,940	24,094,016
23	Research and Development Grant (1/2013-12/2047)	3,100,000		930.2	100,000	3,000,000
24	Environmental Remediation Cost	128,787	9,414	573/592	138,201	
25	Amount Undercollected - Gas Cost Adjustment	14,252,024	73,704,514	431/481	77,429,694	10,526,844
26	Gas WNA Cap - Winter 2015 (11/2016 - 10/2021)	2,091,059		480/481	432,632	1,658,427
27	Gas WNA Cap - Winter 2016 (11/2017 - 10/2022)	914,938	540,728	480/481	48,522	1,407,144
28	Gas WNA Cap - Winter 2017		1,437,141			1,437,141
29	Fukushima Compliance Costs	4,093,530	149,153			4,242,683
30	Undercollected Electric Pension Expense	1,358,450	10,037,514	926	10,817,737	578,227
31	Deferred Long-Term Capacity Contract	14,931,720	22,266,600	555/565	11,178,392	26,019,928
32	Carrying Costs Accrual	32,203,282	18,814,458	426.5	51,017,740	
33	Cyber Compliance Costs	3,743,210	3,056,319	108	2,219,272	4,580,257
34	CIPv5 Compliance Costs	6,935,502	5,312,640			12,248,142
35	Gas Pipeline Integrity Costs	5,956,929	3,861,981	887	1,881,144	7,937,766
36	Undercollected DER and NET Metering Costs	(1,026,240)	22,746,363		21,720,123	
37	Nuclear Refueling Outage Costs		344,956,641	254	3,597,441	341,359,200
38	Deferred Costs Related to Certain Claims					
39	for Tax Deductions and Credits	15,337,175	25,336,049		40,673,224	
40	Deferred Storm Damage Costs	19,706,491	4,087,103			23,793,594
41	Amt. Undercollected - Elec Fuel Adjustment Clause		23,085,027	254	22,689,786	395,241
42						
43						
44	TOTAL	1,903,279,248	944,365,835		1,087,243,103	1,760,401,980

Schedule Page: 232 Line No.: 1 Column: a

As part of the impairment loss associated with the abandonment of the V.C. Summer Units 2 and 3, $68,780,496 was written off to account 426.5 - Other Deductions.

Schedule Page: 232 Line No.: 2 Column: a

SCPSC Docket No. 2002-223-E

Amounts are being amortized through cost of service rates over approximately twenty years.

Schedule Page: 232 Line No.: 3 Column: a

SCPSC Docket No. 89-245-G
SCPSC Docket No. 2008-155-G

Schedule Page: 232 Line No.: 4 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 5 Column: a

SCPSC Docket No. 2005-113-G

Schedule Page: 232 Line No.: 6 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 7 Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

As part of the impairment loss associated with the abandonment of the V.C. Summer Units 2 and 3, $175,005,055 was written off to account 426.5 - Other Deductions.

Schedule Page: 232 Line No.: 7 Column: d

244 / 426.5 / 427

Schedule Page: 232 Line No.: 8 Column: d

118 / 228.3 / 417.1 / 926

Schedule Page: 232 Line No.: 9 Column: d

107 / 228.3 / 417.1 / 926

Schedule Page: 232 Line No.: 10 Column: a

SCPSC Docket No. 2007-418-G

Schedule Page: 232 Line No.: 11 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 12 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 13 Column: a

SCPSC Docket No. 2008-230-E

Schedule Page: 232 Line No.: 14 Column: a

Amortization of deferred balance is a function of customer usage per a Rate Rider mechanism approved by the SCPSC in Docket Nos. 2016-40-E and 2017-35-E.

Schedule Page: 232 Line No.: 15 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 16 Column: a

SCPSC Docket No. 2009-497-E
SCPSC Docket No. 2011-264-E
SCPSC Docket No. 2012-246-E

Schedule Page: 232 Line No.: 17 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 17 Column: d

513 / 553 / 555

Schedule Page: 232 Line No.: 18 Column: a

SCPSC Docket No. 2009-35-G
SCPSC Docket No. 2013-6-G

Schedule Page: 232 Line No.: 19 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 20 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 22 Column: a

SCPSC Docket No. 2008-393-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 23 Column: a

SCPSC Docket No. 2011-513-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 24 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 25 Column: a

SCPSC Docket No. 2017-6-G

Per SCPSC Docket No. 2005-5-G, commodity and demand components of purchased gas cost are recovered separately. Balances for these components as of December 31, 2017 are as follows:

Commodity	($ 230,493)
Demand	10,757,337
Total	$10,526,844

Schedule Page: 232 Line No.: 26 Column: a

SCPSC Docket No. 2016-6-G

Schedule Page: 232 Line No.: 27 Column: a

SCPSC Docket No. 2017-6-G

Schedule Page: 232 Line No.: 29 Column: a

SCPSC Docket No. 2012-277-E

Schedule Page: 232 Line No.: 30 Column: a

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2014-88-E
SCPSC Docket No. 2016-103-E
SCPDC Docket No. 2017-56-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

Schedule Page: 232 Line No.: 31 Column: a

SCPSC Docket No. 2013-276-E

In the docket referenced above, the SCPSC authorized amortization in the amount of $10.8 million annually. Such amortization will remain in effect until the deferred balance is fully amortized.

Schedule Page: 232 Line No.: 32 Column: a

In SCPSC Docket No. 2013-336-E, the SCPSC approved the exclusion from rate base of ADIT assets associated with the treatment of interest capitalized for tax purposes related to new nuclear construction. The SCPSC also approved the accrual of carrying costs on the balance of the ADIT assets removed from rate base, with such carrying costs being deferred as a regulatory asset.

As part of the impairment loss associated with the abandonment of the V.C. Summer Units 2 and 3, these carrying costs were written off to account 426.5 - Other Deductions.

Schedule Page: 232 Line No.: 33 Column: a

SCPSC Docket No. 2015-372-E

Schedule Page: 232 Line No.: 34 Column: a

SCPSC Docket No. 2014-416-E

Schedule Page: 232 Line No.: 35 Column: a

SCPSC Docket No. 2014-461-G

In the docket referenced above, the SCPSC authorized amortization in a levelized annual amount of $1,881,143 beginning in November 2015.

Schedule Page: 232 Line No.: 36 Column: a

SCPSC Docket No. 2014-246-E
SCPSC Docket No. 2015-54-E
SCPSC Docket No. 2016-2-E
SCPSC Docket No. 2017-2-E

Schedule Page: 232 Line No.: 36 Column: d

407.3 / 440 / 442

Schedule Page: 232 Line No.: 37 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 39 Column: a

SCPSC Docket No. 2016-373-E

As part of the impairment loss associated with the abandonment of the V.C. Summer Units 2 and 3, these costs were written off to account 426.5 - Other Deductions.

Schedule Page: 232 Line No.: 39 Column: d

283 / 409 / 426.5

Schedule Page: 232 Line No.: 40 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 41 Column: a

SCPSC Docket No. 2017-2-E

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Noncurrent Receivable - Post					
2	Retirement Benefits	39,215,572	22,158,111	143/253	25,297,557	36,076,126
3	Charleston Garage Revenue Bond					
4	Long-Term	410,313	25,791	143	435,192	912
5	5 year Commitment Fees	3,999,880		427	1,371,386	2,628,494
6	3 Year Commitment Fees	140,862		427	140,862	
7	Progress Payments/Plant Equipmt	7,807,746	14,254,959		16,727,612	5,335,093
8	Directors' Endowment	379,524	34,870	426.2	7,685	406,709
9	Pole Attachment Receivables	2,185,632	4,130,380	143/589	4,119,135	2,196,877
10	Long Term Power Plant Service					
11	Agreement (2007-2021)	1,422,530	14,294,589	107/553	14,775,383	941,736
12	Lease Buyout Costs (2009-2057)	5,079,252		588/880	194,250	4,885,002
13	Department of Energy Nuclear					
14	Loan Guarantee Application					
15	Fee	1,183,076		426.5	1,183,076	
16	Workers' Comp Reserve	376,628	86,248	925	165,153	297,723
17	V. C.Summer Units 2 and 3					
18	Abandoned Construction Costs		3,975,520,191			3,975,520,191
19	Multi-year Cloud Computing					
20	Fees (2014-2017)	26,006		912	26,006	
21	Income Tax Receivable -					
22	Amended Returns	72,124,423	2,238,168	236	21,245,126	53,117,465
23	Other	-579,778	30,990,603		30,162,294	248,531
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47	Misc. Work in Progress	31,470,149				34,411,817
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	165,241,815				4,116,066,676

Schedule Page: 233 Line No.: 7 Column: d

107 / 108 / 131 / 143 / 154 / 182.2 / 186 / 232 / 234 / 553

Schedule Page: 233 Line No.: 18 Column: a

As further described in Note 10 to the Financial Statements, on July 31, 2017 the Company determined to stop the construction of the New Nuclear Units that were being constructed at V.C. Summer Station. As a result of that decision, project costs of approximately $3.976 billion, which is net of an estimated impairment loss of $670 million, have been reclassified from account 107 - Construction Work in Progress to account 186 - Miscellaneous Deferred Debits. The estimated impairment loss of $670 million was recorded to account 426.5 - Other Deductions. The Company plans to file for authorization from the FERC to reclassify the project costs from account 186 - Miscellaneous Deferred Debits to account 182.2 - Unrecovered Plant and Regulatory Study Costs once a determination regarding retail rate recovery is made by the SCPSC.

Schedule Page: 233 Line No.: 23 Column: b

Credit balance due primarily to CIAC awaiting distribution and clearance to capital work order(s).

Schedule Page: 233 Line No.: 23 Column: d

107 / 108 / 131 / 143 / 164 / 184 / 186 / 232 / 236 / 241 / 419 / 432 / 517 / 523 / 524 / 530 / 571 / 593 / 594 / 598 / 803 / 903 / 921 / 923 / 935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Net Operating Loss and Income Tax Credit Carryover		496,109,854
3	Toshiba Settlement		273,260,000
4	Asset Retirement Obligation	143,551,826	93,233,573
5	Remeasurement of Accumulated Deferred Income Taxes		54,851,200
6	Other Post Employment Benefits	62,870,700	42,865,200
7	Other	17,936,100	33,016,500
8	TOTAL Electric (Enter Total of lines 2 thru 7)	224,358,626	993,336,327
9	Gas		
10	Asset Retirement Obligation	10,247,700	7,280,700
11	Other Post Employment Benefits	9,155,000	6,626,800
12	Environmental Remediation	-6,195,000	-3,846,800
13	Incentive Compensation	4,131,300	2,504,600
14	Remeasurement of Accumulated Deferred Income Taxes		1,967,600
15	Other	3,051,500	2,900,600
16	TOTAL Gas (Enter Total of lines 10 thru 15	20,390,500	17,433,500
17	Other (Specify) Non Operating	44,397,878	56,649,954
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	289,147,004	1,067,419,781

Notes

	Balance at Beg. of Year	Balance at End of Year
Line 7 Other:		
Nuclear Unrecovered Plant	0	$21,664,300
Unamortized Investment Tax Credits	$12,841,000	6,746,900
Regulatory Asset Storm Damage	(7,537,800)	(5,936,600)
Major Maintenance	(4,267,700)	(4,772,900)
Executive Deferred Compensation Plan	0	3,713,300
Early Retirement Programs	2,904,400	2,149,300
Rabbi Trust	0	2,046,700
Nuclear Refueling Costs	4,466,400	1,769,600
Reserve for Injuries and Damages	2,655,000	1,602,500
All Other	6,874,800	4,033,400
Total	$17,936,100	$33,016,500

	Balance at Beg. of Year	Balance at End of Year
Line 15 Other:		
Executive Deferred Compensation Plan	0	$ 666,000
Unamortized Investment Tax Credits	$ 903,300	466,700
Inventory Capitalization under 263A	563,800	392,100
Rabbi Trust	0	367,100
Early Retirement Programs	470,600	351,600
Reserve for Injuries and Damages	351,300	241,200
All Other	762,500	415,900
Total	$ 3,051,500	$ 2,900,600

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

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.

	Balance at Beg. of Year	Balance at End of Year
Line 17 Other:		
Income Tax Credit Carryover	0	$25,325,851
Asset Retirement Obligation	$41,058,978	28,291,703
Directors' Endowment	1,244,900	1,436,600
Early Retirement Programs	840,200	548,000
Other Post Employee Benefits	621,300	613,400
All Other	632,500	434,400
Total	$44,397,878	$56,649,954

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

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)
1	Account 201:			
2	Common Stock Issued	50,000,000		
3	Total Common	50,000,000		
4				
5				
6	Account 204:			
7	Preferred Stock Issued	20,000,000		
8	Total Preferred	20,000,000		
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (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 non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
40,296,147	576,405,122					2
40,296,147	576,405,122					3
						4
						5
						6
1,000	100,000					7
1,000	100,000					8
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Schedule Page: 250 Line No.: 2 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: e

These shares are held by SCANA Corporation and do not pay a dividend.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. 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 give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on 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 which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received from Stockholders:	
2	Cash donations by former parent company, General Gas & Electric	
3	Corporation	240,000
4	Equity advance from SCANA to SCE&G from issuance of 2.3 million	
5	shares of common stock (1992)	89,941,500
6	Equity advance from SCANA to SCE&G from issuance of 404,222 shares	
7	of SCANA common stock under the Dividend Reinvestment and Stock	
8	Purchase Plan and 422,082 shares of SCANA common stock under the	
9	Stock Purchase Savings Plan (1992)	36,895,774
10	Equity advance from SCANA to SCE&G from issuance of 529,954 shares	
11	of SCANA common stock under the Dividend Reinvestment and Stock	
12	Purchase Plan and 705,498 shares of SCANA Common Stock under	
13	the Stock Purchase Saving Plan (1993)	58,141,500
14	Equity advance from SCANA to SCE&G from issuance of 595,438 shares	
15	of SCANA common stock under the Dividend Reinvestment and Stock	
16	Purchase Plan and 781,354 shares of SCANA common stock	
17	under the Stock Purchase Savings Plan (1994)	43,425,899
18	Equity advance from SCANA to SCE&G from issuance of 1,434,664	
19	shares of SCANA common stock under the SCANA Investor Plus Plan	
20	and 1,630,993 shares of SCANA common stock under the Stock	
21	Purchase Savings Plan (1996)	53,658,065
22	Equity advance from SCANA to SCE&G from issuance of 4.5 million	
23	shares of SCANA common stock (1995)	85,845,000
24	Equity advance from SCANA to SCE&G from issuance of 1,118,366	
25	shares of SCANA common stock under the SCANA Investor Plus Plan	
26	and 1,393,761 shares of SCANA common stock under the	
27	Stock Purchase Savings Plan (1996)	49,141,871
28	Equity advance from SCANA to SCE&G from issuance of 170,524 shares	
29	of SCANA common stock under the SCANA Investor Plus Plan and	
30	the issuance of 342,409 shares of SCANA common stock under	
31	the Stock Purchase Savings Plan (1997)	12,147,617
32	Reclass of 2001-2003 Capital Contributions from Parent from 211	
33	account "Misc Paid-In Capital"	197,911,200
34	Repayment of Capital Contributions from Parent (2004)	-3,206,660
35	Equity advance from SCANA to SCE&G from issuance of 356,008 shares	
36	of SCANA common stock under the SCANA Investor Plus Plan and	
37	the issuance of 780,472 shares of SCANA common stock under the	
38	Stock Purchase Savings Plan (2004)	41,728,531
39		
40	TOTAL	2,288,167,716

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. 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 give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on 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 which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Reclass of 2005 Capital Contributions from Parent from	
2	account 211 "Misc. Paid in Capital."	4,591,300
3	Equity advance from SCANA to SCE&G from issuance of SCANA common	
4	stock under the SCANA Investor Plus Plan and the Stock Purchase	
5	Saving Plan (2005)	34,697,793
6	Equity advance from SCANA to SCE&G based on SCE&G's funding	
7	requirements	1,394,496,916
8	Income tax benefit true-up	78,259,588
9	Equity advance from SCANA to SCE&G from issuance of SCANA Common	
10	stock	100,500,000
11	Subtotal - Account 208	2,278,415,894
12		
13	Account 209 - Reduction in Par or stated value of Capital Stock	
14	Subtotal - Account 209	
15		
16	Account 210 - Gain on Resale or Cancellation of Reacquired Capital	
17	Stock	
18	Subtotal - Account 210	
19		
20	Account 211 - Miscellaneous Paid - In - Capital:	
21	Merger of Florence Gas Division	6,284,464
22	Revaluation of fixed capital and related depreciation reserves	
23	(1940)	8,547,035
24	Merger of Lexington Water Power Company (1943)	5,418,114
25	Reserves for amounts in excess of original cost of utility plant	
26	(1943)	-9,547,035
27	Discount on purchase of 20 shares of 5% series, $50 par value	
28	preferred stock (1944)	100
29	Revaluation of Florence-Darlington gas properties (1944)	-276,426
30	Disposition of electric and common plant adjustments (1945)	39,140
31	Disposition of other physical property adjustments (1945)	82,567
32	Disposition of gas plant intangibles (1945)	-644,761
33	Adjustments of 1941 land sales by Lexington Water Power	
34	Company (1949)	12,331
35	Funds received from Script Agent under 1946 Plan for Stock	
36	Distribution by former Parent Company (1952, 1953)	98,308
37	Capital Contributions from Parent (2001)	32,908,300
38	Capital Contributions from Parent (2002)	156,780,200
39	Capital Contributions from Parent (2003)	8,222,700
40	TOTAL	2,288,167,716

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. 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 give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on 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 which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Reclass of 2001-2003 Capital Contributions from Parent to	
2	account 208 "Donations Received from Stockholders" (2004)	-197,911,200
3	Other	-262,015
4	Equity advance representing the true up of the benefit allocation	
5	relating to the SCANA tax benefit	4,591,300
6	Reclass of 2005 Capital Contributions from Parent to	
7	account 208 "Donations Received from Stockholders."	-4,591,300
8	Subtotal - Account 211	9,751,822
9		
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40	TOTAL	2,288,167,716

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Common Stock Expense, no par value	4,335,379
2		
3		
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21		
22	TOTAL	4,335,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2			
3	First Mortgage Bonds:		
4	6.625% Series, due 2032	300,000,000	2,928,187
5			2,397,000 D
6			
7	4.50% Series, due 2064	300,000,000	3,244,190
8			3,186,000 D
9			
10	4.50% Series due 2064	75,000,000	656,250
11			1,617,750 D
12			
13	5.25% Series, due 2035	100,000,000	1,032,840
14			1,821,000 D
15			
16	5.30% Series, due 2033	300,000,000	2,678,847
17			579,000 D
18			
19	5.25% Series, due 2018	250,000,000	2,443,883
20			615,000 D
21			
22	5.80% Series, due 2033	200,000,000	1,785,478
23			646,000 D
24			
25	6.25% Series, due 2036	125,000,000	1,240,777
26			421,250 D
27			
28	6.05% Series, due 2038	250,000,000	2,611,037
29			242,500 D
30			
31	6.05% Series, due 2038	110,000,000	962,500
32			5,365,800 D
33	TOTAL	4,929,639,844	49,476,097

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	4.35% Series, due 2042	250,000,000	2,559,708
3			207,500 D
4			
5	4.35% Series, due 2042	250,000,000	2,559,709
6			-21,570,000 P
7			
8	6.50% Series, due 2018	300,000,000	2,214,194
9			861,000 D
10			
11	6.05% Series, due 2038	175,000,000	1,916,924
12			728,000 D
13			
14	5.50% Series, due 2039	150,000,000	1,517,157
15			1,179,000 D
16			
17	3.22% Series, due 2021	30,000,000	329,625
18			
19	5.45% Series, due 2041	250,000,000	2,187,500
20			917,500 D
21			
22	5.45% Series, due 2041	100,000,000	1,361,577
23			-2,799,000 P
24			
25	4.60% Series, due 2043	400,000,000	4,234,911
26			2,000,000 D
27			
28	5.10% Series, due 2065	500,000,000	5,325,812
29			4,035,000 D
30			
31	4.10% Series, due 2046	425,000,000	3,718,750
32			875,500 D
33	TOTAL	4,929,639,844	49,476,097

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2			
3	Pollution Control Facilities Revenue Bonds:		
4	4% Industrial Revenue, due 2028	39,480,000	426,014
5			-2,694,115 P
6			
7	3.625% Industrial Revenue, due 2033	14,735,000	158,164
8			258,157 D
9			
10	Variable Industrial Revenue, due 2038	35,000,000	492,221
11			
12	Amortization of Interest Rate Derivative Contracts:		
13	6.625% $300 Million due 2/1/2032		
14	5.80% $200 Million due 1/15/2033		
15	6.25% $125 Million due 7/1/2036		
16	5.30% $300 Million due 5/21/2033		
17	5.25% $250 Million due 11/1/2018		
18	5.25% $100 Million due 3/1/2035		
19	6.05% $250 Million due 1/15/2038		
20	6.05% $110 Million due 1/15/2038		
21	6.05% $175 Million due 1/15/2038		
22	5.50% $150 Million due 12/15/2039		
23	5.45% $250 Million due 2/1/2041		
24	5.45% $100 Million due 2/1/2041		
25	4.35% $250 Million due 2/01/2042		
26	4.35% $250 Million due 2/01/2042		
27	4.60% $75 Million due 6/14/2043		
28	4.60% $75 Million due 6/14/2043		
29	4.60% $90 Million due 6/14/2043		
30	4.60% $80 Million due 6/14/2043		
31	4.60% $80 Million due 6/14/2043		
32	$35 Million SIFMA due 11/30/2038		
33	TOTAL	4,929,639,844	49,476,097

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.50% $300 Million due 06/01/2064		
2	4.50% $75 Million due 06/01/2064		
3	5.10% $500 Million due 06/01/2065		
4	4.10% $425 Million due 06/15/2046		
5	SUBTOTAL - Account 221	4,929,215,000	49,476,097
6			
7	Account 224 - Other Long Term Debt:		
8	Variable Rate Lines of Credit		
9	Contract on Natural Gas Distribution system		
10	Acquired from Charleston AFB	424,844	
11	Commitment Fees		
12	SUBTOTAL - Account 224	424,844	
13			
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31			
32			
33	TOTAL	4,929,639,844	49,476,097

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
01-31-2002	02-01-2032	01-31-2002	02-01-2032	300,000,000	19,875,000	4
						5
						6
06-01-2014	06-01-2064	06-01-2014	06-01-2064	300,000,000	13,500,000	7
						8
						9
06-13-2016	06-01-2064	06-13-2016	06-01-2064	75,000,000	3,375,000	10
						11
						12
03-08-2005	03-01-2035	03-08-2005	03-01-2035	100,000,000	5,250,000	13
						14
						15
05-21-2003	05-15-2033	05-21-2003	05-15-2033	300,000,000	15,900,000	16
						17
						18
11-06-2003	11-01-2018	11-06-2003	11-01-2018	250,000,000	13,125,000	19
						20
						21
01-23-2003	01-15-2033	01-23-2003	01-15-2033	200,000,000	11,600,000	22
						23
						24
06-27-2006	07-01-2036	06-27-2006	07-01-2036	125,000,000	7,812,500	25
						26
						27
01-14-2008	01-15-2038	01-14-2008	01-15-2038	250,000,000	15,212,725	28
						29
						30
06-24-2008	01-15-2038	06-24-2008	01-15-2038	110,000,000	6,473,500	31
						32
				4,929,015,843	264,157,990	33

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
01-30-2012	02-01-2042	01-30-2012	02-01-2042	250,000,000	10,875,000	2
						3
						4
07-13-2012	02-01-2042	07-13-2012	02-01-2042	250,000,000	10,875,000	5
						6
						7
10-02-2008	11-01-2018	10-02-2008	11-01-2018	300,000,000	19,500,000	8
						9
						10
03-17-2009	01-15-2038	03-17-2009	01-15-2038	175,000,000	10,681,275	11
						12
						13
12-09-2009	12-15-2039	12-09-2009	12-15-2039	150,000,000	8,250,000	14
						15
						16
10-18-2011	10-18-2021	10-18-2011	10-18-2021	30,000,000	966,000	17
						18
01-27-2011	02-01-2041	01-27-2011	02-01-2041	250,000,000	13,625,000	19
						20
						21
05-24-2011	02-01-2041	05-24-2011	02-01-2041	100,000,000	5,450,000	22
						23
						24
06-14-2013	06-15-2043	06-14-2013	06-15-2043	400,000,000	18,400,000	25
						26
						27
06-01-2015	06-01-2065	06-01-2015	06-01-2065	500,000,000	25,500,000	28
						29
						30
06-13-2016	06-15-2046	06-13-2016	06-15-2046	425,000,000	17,425,000	31
						32
				4,929,015,843	264,157,990	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
01-15-2013	02-01-2028	01-15-2013	02-01-2028	39,480,000	1,579,200	4
						5
						6
01-15-2013	02-01-2033	01-15-2013	02-01-2033	14,735,000	534,144	7
						8
						9
12-01-2008	12-01-2038	12-01-2008	12-01-2038	34,555,000	1,017,129	10
						11
						12
		01-31-2002	02-01-2032		-34,443	13
		01-23-2003	01-15-2033		-5,494	14
		06-27-2006	07-01-2036		-206,475	15
		05-21-2003	05-15-2033		339,792	16
		11-06-2003	11-01-2018		319,386	17
		03-08-2005	03-01-2035		48,648	18
		01-14-2008	01-15-2038		280,870	19
		06-24-2008	01-15-2038		-10,696	20
		03-17-2009	01-15-2038		392,825	21
		12-09-2009	12-15-2039		-442,502	22
		01-27-2011	02-01-2041		307,460	23
		05-24-2011	02-01-2041		221,085	24
		01-30-2012	02-01-2042		-266,869	25
		07-13-2012	02-01-2042		-26,593	26
		06-14-2013	06-15-2043		303,415	27
		06-14-2013	06-15-2043		304,315	28
		06-14-2013	06-15-2043		-336,511	29
		06-14-2013	06-15-2043		-301,113	30
		06-14-2013	06-15-2043		-293,377	31
		12-01-2013	11-30-2038		-72,922	32
				4,929,015,843	264,157,990	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		06-01-2014	06-01-2064		171,788	1
		06-13-2016	06-01-2064		71,213	2
		06-01-2015	06-01-2065		335,315	3
		06-13-2016	06-15-2046		1,482,779	4
				4,928,770,000	259,383,369	5
						6
						7
						8
						9
				245,843	11,804	10
					4,762,817	11
				245,843	4,774,621	12
						13
						14
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						16
						17
						18
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						30
						31
						32
				4,929,015,843	264,157,990	33

Schedule Page: 256 Line No.: 1 Column: c

With respect to unamortized amounts (premium, discount or expense) of debt redeemed, the Company follows the provisions set forth in General Instruction No. 17 of the Uniform System of Accounts. The Company records any unamortized amounts related to the redeemed debt to account 189 "Unamortized Loss on Reacquired Debt" or account 257 "Unamortized Gain on Reacquired Debt" as appropriate and amortizes this amount over the life of the new issue if refunded or over the remaining life of the original debt if not refunded.

Schedule Page: 256.3 Line No.: 8 Column: a

The Company had no long-term borrowings against its revolving credit agreements. These agreements expire in December 2018 and December 2020.

Schedule Page: 256.3 Line No.: 10 Column: a

In 2007, the Company was awarded the contract for the privatization of the natural gas distribution system at the Charleston Air Force Base. On September 1, 2007, ownership of the system transferred to the Company and the Company recorded assets totaling $424,844 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off this long-term debt through applied billing credits over a period of 20 years. As of 12/31/2017, the outstanding amount related to this obligation was $245,843.

Schedule Page: 256.3 Line No.: 13 Column: i

The interest expense of $6,717,638 included in account 430 "Interest on Debt to Associated Companies" is related to short-term debt and therefore is not included in this schedule.

Schedule Page: 256.3 Line No.: 15 Column: a

The Company has authorization from the South Carolina Public Service Commission to issue up to $3.5 billion of First Mortgage Bonds(State Commission Order Nos. 2013-277 and 2016-564). As of 12/31/2017, the Company had issued $1.24 billion under such authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	-184,774,492
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized	213,697,167
6	Pension Plan	15,563,853
7	Recovery of Deferred Capacity	296,000
8	Toshiba Settlement	1,095,230,291
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Unrecovered Nuclear Project Costs	1,118,103,792
11	Book Depreciation and Amortization	279,298,402
12	State Income Tax Deduction	120,795,880
13	Other	117,268,205
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	30,049,338
16	Regulatory Asset - Carrying Costs	18,814,443
17	Regulatory Asset Deferred Capacity	11,088,208
18		
19	Deductions on Return Not Charged Against Book Income	
20	Unrecovered Nuclear Project Costs	3,851,652,222
21	Tax Depreciation and Amortization	1,045,455,723
22	Total Net Book Income Tax (including Investment Tax Credit)	178,778,955
23	Repair Allowance Deduction	68,158,727
24	Domestic Production Activities Deduction	37,303,000
25	Deferred Fuel Costs	53,405,870
26	Other	38,516,590
27	Federal Tax Net Income	-2,556,056,032
28	Show Computation of Tax:	
29	Tax @ 35%	-894,619,611
30		
31	Net Operating Loss	702,765,249
32	Other	-7,894,294
33	Current Federal Income Tax Expense Recorded	-200,339,437
34		
35		
36		
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43		
44		

Schedule Page: 261 Line No.: 13 Column: b

Book Expense - Nuclear Fuel	$ 44,074,146
Executive Deferred Compensation Plan	17,552,170
Contributions in Aid of Construction	12,672,760
Regulatory Asset - Unrecovered Plant	11,740,025
Rabbi Trust	9,674,322
Nuclear Decommissioning Expense Accrual	3,224,921
Other Post Retirement Benefits	3,148,056
Section 162m limitation	3,000,000
Directors' Endowment	2,492,269
Net Metering	2,254,897
Book Vehicle Depreciation Charged to Operations	1,467,712
Pollution Control	1,344,598
Amortization of Losses on Reacquired Debt	1,142,385
Meals and Lobbying	814,274
Environmental Remediation Costs	766,570
Uncollectible Accounts	680,889
Long Term Disability	233,465
Deferred VCS Costs	183,816
All Other	800,930
Total	$117,268,205

Schedule Page: 261 Line No.: 26 Column: b

Major Maintenance Programs	$ 7,972,215
Bonus Accrual	7,956,085
Cyber Security Costs	6,149,688
Deferred Nuclear Fuel Expenses	4,584,093
Storm Damage Deferral	4,087,103
Demand Side Management	2,899,657
Gas Pipeline Integrity	1,980,837
Gas WNA Cap	1,496,714
Injuries and Damages	469,818
Early Retirement Programs	398,959
All Other	521,421
Total	$ 38,516,590

Schedule Page: 261 Line No.: 32 Column: b

Research & Development Credits	($10,733,800)
Return to Provision	2,664,367
All Other	175,139
Total	($ 7,894,294)

Schedule Page: 261 Line No.: 33 Column: b

South Carolina Electric & Gas Company is a wholly owned subsidiary of SCANA Corporation and is included in the consolidated federal income tax return of SCANA Corporation. Taxes are allocated to members based on their contributions to the consolidated total. Current federal income taxes recorded in 2017 by each member of the consolidated group were as follows:

SCANA Corporation	($ 37,971,000)
SCANA Communications Holding, Inc.	(3,205)
SCANA Services	0
South Carolina Electric & Gas Company	(201,409,837)*
South Carolina Fuel Company	1,070,400 *
South Carolina Generating Company, Inc.	1,610,488
Public Service Company of North Carolina, Inc.	(19,581,600)
PSNC Blue Ridge Corporation	394,500
PSNC Clean Energy Enterprises, Inc.	(200)
PSNC Cardinal Pipeline Corporation	850,500
SCANA Energy Marketing, Inc.	17,789,000
Total	($237,250,954)

* ($200,339,437)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
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 both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income			-200,339,437	-33,695,654	166,643,783
3	FUTA	5,245		223,208	238,046	13,184
4	FICA	833,811		32,146,465	34,252,125	1,988,191
5	Other Miscellaneous		18,993	56,327	37,334	
6	SUBTOTAL	839,056	18,993	-167,913,437	831,851	168,645,158
7						
8	State:					
9	Income			-55,483	-62,918,333	-62,862,850
10	License			15,938,648	15,938,648	
11	Vehicle License			176,199	193,333	
12	Electric Generation	470,240		7,227,983	7,036,217	
13	SUTA	9,508		460,868	491,928	26,977
14	Other Miscellaneous					
15	SUBTOTAL	479,748		23,748,215	-39,258,207	-62,835,873
16						
17	Local:					
18	County Property	178,828,708	613,577	192,710,487	180,119,109	
19	Municipal Property	9,875,722		10,076,933	9,406,638	
20	SUBTOTAL	188,704,430	613,577	202,787,420	189,525,747	
21						
22						
23						
24						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	190,023,234	632,570	58,622,198	151,099,391	105,809,285

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		-289,065,139			88,725,702	2
3,591		79,264			143,944	3
716,342		11,952,969			20,193,496	4
					56,327	5
719,933		-277,032,906			109,119,469	6
						7
						8
		-17,737,587			17,682,104	9
		14,019,441			1,919,207	10
	17,134				176,199	11
662,007		7,227,983				12
5,425		162,186			298,681	13
						14
667,432	17,134	3,672,023			20,076,191	15
						16
						17
191,421,181	614,673	168,780,327			23,930,160	18
10,546,017		8,835,455			1,241,478	19
201,967,198	614,673	177,615,782			25,171,638	20
						21
						22
						23
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						39
						40
203,354,563	631,807	-95,745,101			154,367,298	41

Schedule Page: 262 Line No.: 2 Column: f

Reclassified amount from account 186 - Misc Deferred Debits	($ 21,245,126)
Overpayment of taxes reclassified to account 143 - Other Accounts Receivable	197,889,327
Reclassified amount from account 190 - Accumulated Deferred Income Tax Assets	(10,000,418)
Total	$ 166,643,783

Schedule Page: 262 Line No.: 3 Column: f

Estimated payroll taxes in the amount of ($855,083) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2017. Those adjustments are combined with a total of $2,883,435 of payroll taxes related to at-risk incentive compensation actually paid in 2017 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of $2,028,352.

Schedule Page: 262 Line No.: 4 Column: f

Estimated payroll taxes in the amount of ($855,083) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2017. Those adjustments are combined with a total of $2,883,435 of payroll taxes related to at-risk incentive compensation actually paid in 2017 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of $2,028,352.

Schedule Page: 262 Line No.: 9 Column: f

Reclassified amount from account 143 - Other Accounts Receivable	($ 18,555,420)
Reclassified amount to account 165 - Prepaid Taxes	14,271,281
Reclassified amount from account 190 - Accumulated Deferred Income Tax Assets	(35,080,031)
Reclassified amount from account 190 - Accumulated Deferred Income Tax Assets	(23,498,680)
Total	($ 62,862,850)

Schedule Page: 262 Line No.: 13 Column: f

Estimated payroll taxes in the amount of ($855,083) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2017. Those adjustments are combined with a total of $2,883,435 of payroll taxes related to at-risk incentive compensation actually paid in 2017 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of $2,028,352.

Schedule Page: 262 Line No.: 22 Column: a

Taxes related to the Company's common utility operations are apportioned to electric and gas operations based on functional usage of common property, revenue or payroll as applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	191,612			411.4	36,000	
4	7%						
5	10%	15,443,846			411.4	910,800	
6	8%	5,050,168			411.4	324,100	
7	20%	44,474			411.4	4,200	
8	TOTAL	20,730,100				1,275,100	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	20,434			411.4	5,100	
13	10%	592,415			411.4	52,400	
14	20%	12,392			411.4	900	
15	8%	832,959			411.4	54,200	
16	Total Gas	1,458,200				112,600	
17							
18							
19							
20							
21							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
155,612	58.4 Years		3
			4
14,533,046	58.4 Years		5
4,726,068	58.4 Years		6
40,274	58.4 Years		7
19,455,000			8
			9
			10
			11
15,334	47.5 Years		12
540,015	47.5 Years		13
11,492	47.5 Years		14
778,759	47.5 Years		15
1,345,600			16
			17
			18
			19
			20
			21
			22
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			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER DEFFERED 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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accrued Pension Liability - Early					
2	Retirement Incentive Programs &					
3	Other	8,872,191		850,386	625,093	8,646,898
4	Accrued Liability - Incentive Plan	4,633,377	107/118/920	22,303,204	19,281,612	1,611,785
5	Gas Environmental Remediation	10,222,833	182.3	40,107,524	39,833,003	9,948,312
6	Other Environmental Remediation	611,576	182.3/131	2,415,078	2,403,502	600,000
7	Long-Term Disability	931,236	131	512,519	775,808	1,194,525
8	Accrued Liability - Director's					
9	Endowment Program	3,254,778	131	78,328	2,581,503	5,757,953
10	Life Insurance Premium Obligation	3,057	926	3,092	35	
11	Santee River Basin Accord	1,046,125	131	97,523		948,602
12	Municipal Nonstandard Service Fund					
13	Matching Obligation	5,745,151	186	23,052,971	23,786,160	6,478,340
14	SRS Substation	1,805,320	456	96,284		1,709,036
15	Interconnection Study Deposits	317,844	234/456	2,036,827	5,588,371	3,869,388
16	CIAC Obligations	17,235,908	107	129,317	217,653	17,324,244
17	Noncontrolling Interest - SCFC	2,696,226			1,477,086	4,173,312
18	FIN 48 Interest	2,358,800	431	696,481	8,207,734	9,870,053
19	Other	950,757		2,546,254	3,175,279	1,579,782
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46						
47	TOTAL	60,685,179		94,925,788	107,952,839	73,712,230

Schedule Page: 269 Line No.: 3 Column: c

186 / 426.5 / 131

Schedule Page: 269 Line No.: 19 Column: c

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	12,039,300		294,300
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	12,039,300		294,300
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	12,039,300		294,300
18	Classification of TOTAL			
19	Federal Income Tax	10,465,500		255,800
20	State Income Tax	1,573,800		38,500
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						11,745,000	4
							5
							6
							7
						11,745,000	8
							9
							10
							11
							12
							13
							14
							15
							16
						11,745,000	17
							18
						10,209,700	19
						1,535,300	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFFERED 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 accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,826,474,530	353,833,200	523,806,600
3	Gas	169,739,500	20,127,300	5,251,200
4	Other - Non Operating	7,453,500		
5	TOTAL (Enter Total of lines 2 thru 4)	2,003,667,530	373,960,500	529,057,800
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,003,667,530	373,960,500	529,057,800
10	Classification of TOTAL			
11	Federal Income Tax	1,778,397,540	335,545,900	459,211,700
12	State Income Tax	225,269,990	38,414,600	69,846,100
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3/254	872,169,600	182.3/254	85,392,797	869,724,327	2
		182.3/254	90,623,400	182.3/254	1,383,400	95,375,600	3
27,900	2,538,200					4,943,200	4
27,900	2,538,200		962,793,000		86,776,197	970,043,127	5
							6
							7
							8
27,900	2,538,200		962,793,000		86,776,197	970,043,127	9
							10
	2,526,700		946,470,485		74,817,016	780,551,571	11
27,900	11,500		16,322,515		11,959,181	189,491,556	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: h

Adjustment for remeasurement of deferred income taxes resulting from federal income tax reform.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFFERED 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 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Unrecovered Nuclear Proj Costs		1,449,729,000	207,900
4	Regulatory Asset - ARO	122,670,000	618,700	5,897,000
5	Employee Benefit Plan Costs	80,966,300	3,296,000	15,599,800
6	Unrecovered Plant Canadys	44,576,800	4,800	4,490,600
7	Prepayments	25,783,900	198,900	34,300
8	All Other	6,695,300	88,940,900	17,236,600
9	TOTAL Electric (Total of lines 3 thru 8)	280,692,300	1,542,788,300	43,466,200
10	Gas			
11	Employee Benefit Plan Costs	11,508,200	811,000	804,600
12	Regulatory Asset - ARO	6,897,000	519,500	
13	Deferred Fuel Costs	5,451,400	3,376,400	4,801,300
14	Pension Plan Income	-1,057,900	7,114,400	2,178,900
15	Prepayments	3,649,700	34,300	168,900
16	All Other	4,098,900	1,330,100	101,600
17	TOTAL Gas (Total of lines 11 thru 16)	30,547,300	13,185,700	8,055,300
18	Non Operating	63,001,000		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	374,240,600	1,555,974,000	51,521,500
20	Classification of TOTAL			
21	Federal Income Tax	325,296,400	1,352,611,500	44,786,600
22	State Income Tax	48,944,200	203,362,500	6,734,900
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
			524,409,500	426.5	58,649,200	983,760,800	3
			40,818,600			76,573,100	4
			23,874,700			44,787,800	5
			13,940,200			26,150,800	6
			9,022,600			16,925,900	7
			30,709,900			47,689,700	8
			642,775,500		58,649,200	1,195,888,100	9
							10
			4,003,800			7,510,800	11
			2,578,800			4,837,700	12
			1,400,100			2,626,400	13
			1,348,300			2,529,300	14
			1,222,200			2,292,900	15
			1,852,400			3,475,000	16
			12,405,600			23,272,100	17
7,915,300	48,663,900		22,622,000			-369,600	18
7,915,300	48,663,900		677,803,100		58,649,200	1,218,790,600	19
							20
6,880,600	42,302,600		674,126,900		50,949,600	974,522,000	21
1,034,700	6,361,300		3,676,200		7,699,600	244,268,600	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 4 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 5 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 6 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 7 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 8 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Demand Side Management Costs	$22,808,700	$ 1,109,100	-	($ 8,316,500)	$15,601,300
Pension Plan	(20,220,400)	56,046,800	$12,664,800	(8,053,600)	15,108,000
Regulatory Asset- Deferred Capacity	6,531,400	4,241,200	-	(3,744,600)	7,028,000
Cyber Security Costs	4,084,600	2,352,300	-	(2,238,200)	4,198,700
Reacquired Debt	5,193,100	-	404,200	(1,665,200)	3,123,700
FAS109 - Sec 174	4,653,500	-	-	(4,653,500)	-
Deferred VCS Costs	1,794,000	-	70,300	(599,400)	1,124,300
Fukushima Compliance	1,565,800	57,100	-	(564,300)	1,058,600
Grants	994,500	153,000	-	(399,000)	748,500
Regulatory Asset- Professional Fees	643,700	5,400	-	(649,100)	-
Deferred Fuel Costs	(22,207,800)	22,092,400	238,000	122,900	(230,500)
Recovery of Deferred Capacity	397,500	-	113,200	(100,100)	184,200
All Other	456,700	2,883,600	3,746,100	150,700	(255,100)
Total	$ 6,695,300	$88,940,900	$17,236,600	($30,709,900)	$47,689,700

Schedule Page: 276 Line No.: 8 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 11 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 12 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 13 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 14 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 15 Column: g
182.3 / 254
Schedule Page: 276 Line No.: 16 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Gas Pipeline Integrity	$2,278,600	$ 757,600	-	($1,055,700)	$ 1,980,500
Gas WNA Cap	1,149,800	572,500	-	(598,900)	1,123,400
Reaquired Debt	588,900	-	$ 32,700	(193,400)	362,800
Regulatory Asset Customer Programs	81,600	-	68,900	(4,400)	8,300
Total	$ 4,098,900	$1,330,100	$ 101,600	($1,852,400)	$ 3,475,000

Schedule Page: 276 Line No.: 16 Column: g

182.3 / 254

Schedule Page: 276 Line No.: 18 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.2	Amt. Credited Acct.411.2	Adjust.	Balance at End of Year
Regulatory Asset- Carrying Costs	$12,317,700	$ 7,196,600	-	($19,514,300)	-
Pension Plan	50,331,200	10,600	$48,376,300	(117,800)	$1,847,700
FIN48 Interest	371,800	160,900	255,700	-	277,000
All Other	(19,700)	547,200	31,900	(2,989,900)	(2,494,300)
Total	$63,001,000	$ 7,915,300	$48,663,900	($22,622,000)	($ 369,600)

Schedule Page: 276 Line No.: 18 Column: g

182.3 / 219

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Accumulated Deferred Income Tax Credits	13,744,300	190	6,530,700		7,213,600
2	Nuclear Refueling Accrual	11,677,072	524/528	34,674,722	30,090,629	7,092,979
3	NOX Emission Allowance Proceeds	1,033			2	1,035
4	Interest Rate Derivatives (3/2009-6/2043)	150,630,173		26,976,962	6,945,737	130,598,948
5	Demand Side Management Carrying Costs	4,732,811	182.3	1,507,745	491,402	3,716,468
6	SO2 Emission Allowance Proceeds	957			71	1,028
7	Wholesale Fuel Overcollection	1,867,344	447	1,139,200	795,614	1,523,758
8	Amt. Overcollected - Elec Fuel Adjustment Clause	56,192,258	449/173	296,124,164	239,931,906	
9	Overcollected DER and Net Metering Costs				3,281,137	3,281,137
10	Environmental Remediation Costs				113,154	113,154
11	Monetization of Toshiba Settlement				1,095,230,291	1,095,230,291
12	Excess Deferred Tax Liabilities		190	215,343,600	1,452,647,800	1,237,304,200
13						
14						
15						
16						
17						
18						
19						
20						
21						
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34						
35						
36						
37						
38						
39						
40						
41	TOTAL	238,845,948		582,297,093	2,829,527,743	2,486,076,598

Schedule Page: 278 Line No.: 2 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 278 Line No.: 4 Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

As part of the impairment loss associated with the abandonment of the V.C. Summer Units 2 and 3, $1,498,875 was written off to account 426.5 - Other Deductions.

Schedule Page: 278 Line No.: 4 Column: c

176 / 426.5 / 427

Schedule Page: 278 Line No.: 5 Column: a

SCPSC Docket No. 2013-50-E
SCPSC Docket No. 2013-208-E
SCPSC Docket No. 2014-44-E
SCPSC Docket No. 2015-45-E
SCPSC Docket No. 2016-40-E
SCPSC Docket No. 2017-35-E

Schedule Page: 278 Line No.: 8 Column: a

SCPSC Docket No. 2017-2-E

Schedule Page: 278 Line No.: 9 Column: a

SCPSC Docket No. 2014-246-E
SCPSC Docket No. 2015-54-E
SCPSC Docket No. 2016-2-E
SCPSC Docket No. 2017-2-E

Schedule Page: 278 Line No.: 10 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 278 Line No.: 11 Column: a

Includes net proceeds received under or arising from the monetization of the Settlement Agreement dated as of July 27, 2017 with Toshiba Corporation. The Company expects the SCPSC to approve the use of these net proceeds for the benefit of customers in a future filing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,177,448,291	1,184,394,884
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	872,913,706	850,736,352
5	Large (or Ind.) (See Instr. 4)	463,892,197	433,854,479
6	(444) Public Street and Highway Lighting	15,189,324	14,775,119
7	(445) Other Sales to Public Authorities	48,658,415	47,755,097
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,578,101,933	2,531,515,931
11	(447) Sales for Resale	45,729,670	45,568,557
12	TOTAL Sales of Electricity	2,623,831,603	2,577,084,488
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,623,831,603	2,577,084,488
15	Other Operating Revenues		
16	(450) Forfeited Discounts	7,105,721	6,778,151
17	(451) Miscellaneous Service Revenues	4,381,157	4,156,675
18	(453) Sales of Water and Water Power	378,178	385,910
19	(454) Rent from Electric Property	18,871,203	19,530,616
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	755,653	3,598,591
22	(456.1) Revenues from Transmission of Electricity of Others	9,102,714	7,839,445
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	40,594,626	42,289,388
27	TOTAL Electric Operating Revenues	2,664,426,229	2,619,373,876

ELECTRIC OPERATING REVENUES (Account 400)

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 pages 108-109, 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.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,781,917	8,139,813	615,096	605,717	2
				3
7,385,071	7,518,727	95,579	94,375	4
6,212,151	6,264,991	777	783	5
75,048	74,895	1,016	1,025	6
508,884	525,787	3,124	3,125	7
				8
				9
21,963,071	22,524,213	715,592	705,025	10
915,998	946,981	3	4	11
22,879,069	23,471,194	715,595	705,029	12
				13
22,879,069	23,471,194	715,595	705,029	14

Line 12, column (b) includes $ 107,382,697 of unbilled revenues.

Line 12, column (d) includes 845,750 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 5 Column: d

Includes 3,327 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 5 Column: e

Includes 3,332 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 10 Column: b

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$19,543,781
Commercial	18,858,755
Industrial	16,666,350
Street Lighting	202,237
Other Public Authorities	1,311,228
	$56,582,351

Includes Unmetered Sales Revenue as follows:

Residential	$18,907,222
Commercial/Industrial	29,347,501
Street Lighting	13,894,801
Other Public Authorities	123,795
	$62,273,319

Schedule Page: 300 Line No.: 10 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($10,769,575)
Commercial	(10,195,741)
Industrial	(8,965,839)
Street Lighting	(108,360)
Other Public Authorities	(720,965)
	($30,760,480)

Includes Unmetered Sales Revenue as follows:

Residential	$18,994,642
Commercial/Industrial	29,322,905
Street Lighting	13,766,984
Other Public Authorities	137,414
	$62,221,945

Schedule Page: 300 Line No.: 10 Column: d

Includes Unmetered MWH Sales as follows:

Residential	81,342
Commercial/Industrial	152,948
Street Lighting	68,116
Other Public Authorities	863
	303,269

Schedule Page: 300 Line No.: 10 Column: e

Includes Unmetered MWH Sales as follows:

Residential	81,266
Commercial/Industrial	149,291
Street Lighting	67,525
Other Public Authorities	988
	299,070

Schedule Page: 300 Line No.: 10 Column: f

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	211,171
Commercial/Industrial	25,075
Street Lighting	1,099
Other Public Authorities	61
	237,406

Schedule Page: 300 Line No.: 10 Column: g

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	210,488
Commercial/Industrial	24,928
Street Lighting	1,075
Other Public Authorities	59
	236,550

Schedule Page: 300 Line No.: 17 Column: b

Includes $1,490,467 of reconnect and lighting disconnect charges.

Includes $2,554,990 of transmission maintenance fee revenue.

Includes $733,869 of returned check fees.

Account balance also includes debit activity of ($540,787) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 17 Column: c

Includes $1,457,749 of reconnect and lighting disconnect charges.

Includes $2,445,935 of transmission maintenance fee revenue.

Includes $538,840 of returned check fees.

Account balance also includes debit activity of ($439,186) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 21 Column: b

Includes ($393,437) associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $416,168 of Telecommunication Tower Rent Revenue.

Schedule Page: 300 Line No.: 21 Column: c

Includes $1,998,242 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $415,235 of Telecommunication Tower Rent Revenue.

Includes $343,345 of Ground and Telecommunication Rack lease Revenue.

Includes $434,741 of Timber Sales Revenue.

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)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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16					
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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	Residential Sales by Rate					
2	1	311,134	45,047,559	21,185	14,687	0.1448
3	2	25,115	4,831,484	15,895	1,580	0.1924
4	5	994	147,666	69	14,406	0.1486
5	6	448,355	65,014,174	31,124	14,405	0.1450
6	7	274	35,054	11	24,909	0.1279
7	8	6,883,305	1,038,228,014	542,075	12,698	0.1508
8	E1N	1,633	243,389	219	7,457	0.1490
9	E2N	59	18,134	90	656	0.3074
10	E5N	7	1,028	1	7,000	0.1469
11	E6N	2,038	309,606	320	6,369	0.1519
12	E8N	23,667	3,726,490	3,863	6,127	0.1575
13	M1N	286	41,680	19	15,053	0.1457
14	M2N	5	1,395	7	714	0.2790
15	M5N	4	675	1	4,000	0.1688
16	M6N	430	63,636	37	11,622	0.1480
17	M8N	2,418	364,810	181	13,359	0.1509
18	Special (A)	82,193	19,373,497	211,171	389	0.2357
19	Total Residential	7,781,917	1,177,448,291	826,268	9,418	0.1513
20						
21	Commerical & Industrial Sales					
22	by Rate					
23	3	18,330	2,250,550	428	42,827	0.1228
24	9	2,641,439	378,200,841	80,023	33,008	0.1432
25	10	4,699	1,015,950	2,371	1,982	0.2162
26	11	12,519	1,403,777	321	39,000	0.1121
27	12	154,208	18,667,800	3,683	41,870	0.1211
28	14	20,446	3,183,523	1,836	11,136	0.1557
29	16	43,881	6,186,918	2,906	15,100	0.1410
30	20	1,869,792	207,730,248	2,150	869,671	0.1111
31	21	350,557	35,851,663	550	637,376	0.1023
32	22	419,721	52,785,492	1,720	244,024	0.1258
33	23	4,037,964	317,700,862	124	32,564,226	0.0787
34	24	1,991,398	176,683,527	177	11,250,836	0.0887
35	27	951,814	67,426,735	10	95,181,400	0.0708
36	28	2,365	310,473	20	118,250	0.1313
37	60	926,855	37,503,985	3	308,951,667	0.0405
38	E9N	988	142,613	34	29,059	0.1443
39	Special (A)	150,245	29,760,946	24,517	6,128	0.1981
40	Total Commercial & Industrial	13,597,221	1,336,805,903	120,873	112,492	0.0983
41	TOTAL Billed	21,117,321	2,470,719,236	0	0	0.1170
42	Total Unbilled Rev.(See Instr. 6)	845,750	107,382,697	0	0	0.1270
43	TOTAL	21,963,071	2,578,101,933	0	0	0.1174

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	Public Street & Highway					
2	Lighting Sales by Rate					
3	3	1,250	173,756	100	12,500	0.1390
4	9	2,268	460,955	532	4,263	0.2032
5	13	3,743	513,517	384	9,747	0.1372
6	Special (A)	67,788	14,041,096	1,080	62,767	0.2071
7	Total Public Street & Hwy Lights	75,049	15,189,324	2,096	35,806	0.2024
8						
9	Other Sales to Public Authorities					
10	by Rate					
11	3	141,972	17,349,864	2,918	48,654	0.1222
12	9	1,391	221,425	144	9,660	0.1592
13	20	12,109	1,212,137	7	1,729,857	0.1001
14	21	2,903	275,861	2	1,451,500	0.0950
15	65	67,231	5,403,217	21	3,201,476	0.0804
16	66	283,100	24,165,573	33	8,578,788	0.0854
17	Special (A)	178	30,338	11	16,182	0.1704
18	Total OPAs	508,884	48,658,415	3,136	162,272	0.0956
19						
20						
21						
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27						
28						
29						
30						
31						
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35						
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39						
40						
41	TOTAL Billed	21,117,321	2,470,719,236	0	0	0.1170
42	Total Unbilled Rev.(See Instr. 6)	845,750	107,382,697	0	0	0.1270
43	TOTAL	21,963,071	2,578,101,933	0	0	0.1174

Schedule Page: 304 Line No.: 19 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$19,543,781
Commercial	18,858,755
Industrial	16,666,350
Street Lighting	202,237
Other Public Authorities	1,311,228
	$56,582,351

Schedule Page: 304 Line No.: 40 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$19,543,781
Commercial	18,858,755
Industrial	16,666,350
Street Lighting	202,237
Other Public Authorities	1,311,228
	$56,582,351

Schedule Page: 304.1 Line No.: 7 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$19,543,781
Commercial	18,858,755
Industrial	16,666,350
Street Lighting	202,237
Other Public Authorities	1,311,228
	$56,582,351

Schedule Page: 304.1 Line No.: 18 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$19,543,781
Commercial	18,858,755
Industrial	16,666,350
Street Lighting	202,237
Other Public Authorities	1,311,228
	$56,582,351

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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 interest or 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 projected 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 out of 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 from 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 year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Town of McCormick	RQ		4.0	3.9	3.9
2	City of Orangeburg	RQ		131.0	147.6	144.7
3	Town of Winnsboro	RQ		12.1	11.5	11.6
4	Cargill Power Markets, LLC	OS				
5	The Energy Authority, Inc.	OS				
6	Emissions Allow Sales - Revenue Contra					
7	Wholesale Fuel Over/Under Collection					
8						
9						
10	Transmission Revenue included in					
11	Energy Charges Column (i).					
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 an 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 of the schedule. Report subtotals and total for columns (9) 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 billing demand in column (d), the average monthly 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, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) 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 monthly 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, in 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 the 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-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
19,801	588,762	635,691		1,224,453	1
834,681	11,506,116	29,074,250		40,580,366	2
60,186	1,280,152	2,173,348		3,453,500	3
1,300		59,900		59,900	4
30		1,260		1,260	5
			-4	-4	6
			410,195	410,195	7
					8
					9
					10
					11
					12
					13
					14
914,668	13,375,030	31,883,289	0	45,258,319	
1,330	0	61,160	410,191	471,351	
915,998	**13,375,030**	**31,944,449**	**410,191**	**45,729,670**	

Schedule Page: 310 Line No.: 1 Column: c

FERC Electric Tariff, Fourth Revised Volume No. 1

Schedule Page: 310 Line No.: 2 Column: c

FERC Electric Rate Schedule No. 60

Schedule Page: 310 Line No.: 3 Column: c

FERC Electric Rate Schedule Winnsboro PSA

Schedule Page: 310 Line No.: 4 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 4 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 5 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 5 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 6 Column: j

Transfer gain/loss on sale of emission allowances to account 254 for purchasing future emission allowances.

Schedule Page: 310 Line No.: 7 Column: j

Over/under collection of fuel relating to sales to wholesale customers.

Schedule Page: 310 Line No.: 11 Column: i

Subtotal non-RQ of $61,160 includes transmission revenue for OS service of $13,215. Transmission base revenue totals $12,651 and ancillary services revenue totals $564.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,869,872	2,542,754
5	(501) Fuel	248,499,265	241,232,166
6	(502) Steam Expenses	17,149,655	16,631,366
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	6,093,991	6,020,395
10	(506) Miscellaneous Steam Power Expenses	6,469,077	5,762,431
11	(507) Rents		4,500
12	(509) Allowances	-366,497	-137,732
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	280,715,363	272,055,880
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	73,725	91,613
16	(511) Maintenance of Structures	728,704	1,361,389
17	(512) Maintenance of Boiler Plant	12,510,670	12,333,379
18	(513) Maintenance of Electric Plant	11,553,896	11,543,547
19	(514) Maintenance of Miscellaneous Steam Plant	4,841,687	4,513,165
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	29,708,682	29,843,093
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	310,424,045	301,898,973
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	11,205,587	12,421,296
25	(518) Fuel	44,074,146	56,467,219
26	(519) Coolants and Water	3,305,652	2,876,256
27	(520) Steam Expenses	7,690,720	6,316,647
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	3,123,002	1,566,158
31	(524) Miscellaneous Nuclear Power Expenses	41,638,023	41,091,216
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	111,037,130	120,738,792
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-664,682	15,200,712
36	(529) Maintenance of Structures	3,383,970	2,738,627
37	(530) Maintenance of Reactor Plant Equipment	17,497,562	3,069,010
38	(531) Maintenance of Electric Plant	4,777,174	2,500,132
39	(532) Maintenance of Miscellaneous Nuclear Plant	11,124,531	10,319,397
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	36,118,555	33,827,878
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	147,155,685	154,566,670
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	686,614	702,170
45	(536) Water for Power		
46	(537) Hydraulic Expenses	1,427,863	1,286,134
47	(538) Electric Expenses	152,197	181,718
48	(539) Miscellaneous Hydraulic Power Generation Expenses	675,952	1,089,500
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	2,942,626	3,259,522
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	188,108	152,188
54	(542) Maintenance of Structures	3,014	18,362
55	(543) Maintenance of Reservoirs, Dams, and Waterways	540,829	702,406
56	(544) Maintenance of Electric Plant	3,199,180	3,104,540
57	(545) Maintenance of Miscellaneous Hydraulic Plant	106,160	110,419
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,037,291	4,087,915
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	6,979,917	7,347,437

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,142,965	1,100,946
63	(547) Fuel	203,233,276	165,339,292
64	(548) Generation Expenses	4,896,049	5,023,761
65	(549) Miscellaneous Other Power Generation Expenses	1,382,343	1,554,627
66	(550) Rents	44,000	40,800
67	TOTAL Operation (Enter Total of lines 62 thru 66)	210,698,633	173,059,426
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	361,381	345,076
70	(552) Maintenance of Structures	466,043	553,263
71	(553) Maintenance of Generating and Electric Plant	13,032,968	13,764,550
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	526,860	663,459
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	14,387,252	15,326,348
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	225,085,885	188,385,774
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	249,852,730	254,194,400
77	(556) System Control and Load Dispatching	2,834,770	2,718,759
78	(557) Other Expenses	298,944	263,750
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	252,986,444	257,176,909
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	942,631,976	909,375,763
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	800,538	792,884
84			
85	(561.1) Load Dispatch-Reliability	1,058,181	1,076,009
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	873,281	773,525
87	(561.3) Load Dispatch-Transmission Service and Scheduling	177,360	169,113
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	45,768	45,352
90	(561.6) Transmission Service Studies	-600	3,905
91	(561.7) Generation Interconnection Studies	-64,575	-196,944
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,890,634	437,299
94	(563) Overhead Lines Expenses	144,252	51,577
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	2,970,867	2,535,425
97	(566) Miscellaneous Transmission Expenses	4,514,387	3,600,428
98	(567) Rents	353,741	340,147
99	TOTAL Operation (Enter Total of lines 83 thru 98)	13,763,834	9,628,720
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	43,216	24,142
102	(569) Maintenance of Structures	37,157	27,498
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		4,839
105	(569.3) Maintenance of Communication Equipment	32,168	31,563
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,521,990	2,860,584
108	(571) Maintenance of Overhead Lines	6,421,113	5,133,521
109	(572) Maintenance of Underground Lines	1,417	15,803
110	(573) Maintenance of Miscellaneous Transmission Plant	231,736	245,447
111	TOTAL Maintenance (Total of lines 101 thru 110)	9,288,797	8,343,397
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,052,631	17,972,117

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
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 Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	842,319	846,719
135	(581) Load Dispatching	977,324	973,693
136	(582) Station Expenses	564,570	574,535
137	(583) Overhead Line Expenses	1,292,641	1,464,753
138	(584) Underground Line Expenses	235,083	241,818
139	(585) Street Lighting and Signal System Expenses	302,250	416,277
140	(586) Meter Expenses	1,355,043	1,075,373
141	(587) Customer Installations Expenses	28,593	24,362
142	(588) Miscellaneous Expenses	8,989,892	7,483,654
143	(589) Rents	2,223,853	2,169,852
144	TOTAL Operation (Enter Total of lines 134 thru 143)	16,811,568	15,271,036
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	250,917	247,985
147	(591) Maintenance of Structures	1,883	6,720
148	(592) Maintenance of Station Equipment	3,475,504	3,516,089
149	(593) Maintenance of Overhead Lines	25,008,953	26,028,775
150	(594) Maintenance of Underground Lines	3,290,779	3,121,335
151	(595) Maintenance of Line Transformers	121,830	134,260
152	(596) Maintenance of Street Lighting and Signal Systems	3,024,773	3,634,155
153	(597) Maintenance of Meters	398,504	311,848
154	(598) Maintenance of Miscellaneous Distribution Plant	3,100,055	2,975,746
155	TOTAL Maintenance (Total of lines 146 thru 154)	38,673,198	39,976,913
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	55,484,766	55,247,949
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,037,849	1,558,673
160	(902) Meter Reading Expenses	1,845,798	1,895,936
161	(903) Customer Records and Collection Expenses	34,283,756	35,636,476
162	(904) Uncollectible Accounts	6,601,686	5,927,251
163	(905) Miscellaneous Customer Accounts Expenses	2,751,363	2,812,218
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	46,520,452	47,830,554

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	256,568	278,681
168	(908) Customer Assistance Expenses	14,101,484	14,392,900
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	9,254	98,018
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	14,367,306	14,769,599
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	652	
175	(912) Demonstrating and Selling Expenses	1,130,982	1,195,106
176	(913) Advertising Expenses	242	1,872
177	(916) Miscellaneous Sales Expenses	337,186	227,932
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,469,062	1,424,910
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	42,880,412	63,602,777
182	(921) Office Supplies and Expenses	14,645,220	18,141,449
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	15,658,407	13,514,667
185	(924) Property Insurance	7,029,273	7,022,817
186	(925) Injuries and Damages	8,734,868	6,898,273
187	(926) Employee Pensions and Benefits	51,172,176	55,383,403
188	(927) Franchise Requirements	14,374	6,077
189	(928) Regulatory Commission Expenses	6,071,202	5,244,577
190	(929) (Less) Duplicate Charges-Cr.	9,555,489	8,142,846
191	(930.1) General Advertising Expenses	19,861	20,700
192	(930.2) Miscellaneous General Expenses	18,017,744	18,051,631
193	(931) Rents	5,119,901	5,078,266
194	TOTAL Operation (Enter Total of lines 181 thru 193)	159,807,949	184,821,791
195	Maintenance		
196	(935) Maintenance of General Plant	6,333,221	6,905,304
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	166,141,170	191,727,095
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,249,667,363	1,238,347,987

Schedule Page: 320 Line No.: 12 Column: b

Credit due to the sale of CSAPR NOX Ozone Season allowances.

Schedule Page: 320 Line No.: 12 Column: c

Credit due to the recognition, upon termination of the CAIR program, of previously realized gains from the sale of NOX emission allowances previously deferred in Account 254 - Other Regulatory Liabilities.

Schedule Page: 320 Line No.: 35 Column: b

In SCPSC Docket No. 2012-218-E, the SCPSC authorized the Company to establish a 5-cycle or 90 month recovery of nuclear outage costs for V.C. Summer Nuclear Station Unit 1. Accordingly, the Company is accruing $17.2 million annually with $13.8 million and $3.4 million being accrued to account 528 and 524, respectively. Differences between actual outage costs incurred and the accrued amounts are recognized as regulatory assets or liabilities as appropriate. During 2017, the Company reversed actual outage costs of $18.0 million from account 528 and applied such costs against the established regulatory liability. As a result, the Company has reported net credit activity for the year in account 528.

Schedule Page: 320 Line No.: 197 Column: b

For the formula rate approved in the FERC proceeding listed on page 106, administrative and general expenses allocable to transmission exclude $12,296,946 for severance payments related to production.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for 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. Explain in a footnote any ownership interest or affiliation the 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 projects load for this service in its system resource 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 consumers.

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 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 firm service which 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 date that either buyer or seller can unilaterally get out of 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 from transmission constraints, must match the availability 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 year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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 for each adjustment.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Georgia Power	OS	Schedule #793			
2	Newberry Electric Cooperative	RQ				
3	Santee Cooper	RQ				
4	Santee Cooper	RQ				
5	Columbia Energy LLC	OS	Tariff #1			
6	International Paper	OS				
7	Misc Territorial Customers	OS	Rate-PR1			
8	Southeastern Power Administration	RQ	1/2001,12/2002			
9	South Carolina Generating Company, Inc	AD	Schedule #1		446	385
10	Cargill Power Markets, LLC	OS	Schedule #1			
11	Duke Energy Carolinas, LLC	OS	Tariff #5			
12	Exelon Generation Company, LLC	OS	Tariff #3			
13	Macquarie Energy LLC	OS	Tariff #4			
14	Morgan Stanley Capital Group, Inc.	OS	Tariff #2			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for 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. Explain in a footnote any ownership interest or affiliation the 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 projects load for this service in its system resource 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 consumers.

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 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 firm service which 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 date that either buyer or seller can unilaterally get out of 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 from transmission constraints, must match the availability 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 year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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 for each adjustment.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	North Carolina Municipal Power Agency					
2	Agency No. 1	OS				
3	Rainbow Energy Marketing Corporation	OS	Tariff #1			
4	Southern Company Services, Inc.	OS	Tariff #4			
5	The Energy Authority, Inc	OS	12/1/2004			
6	Duke Energy Carolinas, LLC	OS				
7	Duke Energy Progress, LLC	OS				
8	Columbia Energy LLC	IU	Tariff #1			
9	Santee Cooper	LF		25		
10	Columbia Energy LLC	EX	Tariff #5			
11	Barnwell Solar, LLC	OS				
12	Cameron Solar II, LLC	OS				
13	Haley Solar I, LLC	OS				
14	Odyssey Solar, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for 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. Explain in a footnote any ownership interest or affiliation the 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 projects load for this service in its system resource 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 consumers.

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 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 firm service which 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 date that either buyer or seller can unilaterally get out of the contract.

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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability 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 year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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 for each adjustment.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Ridgeland Solar Farm I, LLC	OS				
2	Saluda Solar II, LLC	OS				
3	Saluda Solar, LLC	OS				
4	TIG Sun Energy III, LLC	OS				
5	TIG Sun Energy IV, LLC	OS				
6	Cameron Solar, LLC	OS				
7	Champion Solar, LLC	OS				
8	Estill Solar I, LLC	OS				
9	Estill Solar II, LLC	OS				
10	Hampton Solar I, LLC	OS				
11	Hampton Solar II, LLC	OS				
12	Southern Current One, LLC	OS				
13	St. Matthews Solar, LLC	OS				
14	Swamp Fox Solar, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for 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. Explain in a footnote any ownership interest or affiliation the 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 projects load for this service in its system resource 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 consumers.

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 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 firm service which 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 date that either buyer or seller can unilaterally get out of the contract.

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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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Moffett Solar 1, LLC	OS				
2	Billing Credit Agreement (BCA)					
3	DER Solar Power Purchases	OS				
4	Adjustments					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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 explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, 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 average billing demand in column (d), the average monthly 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, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) 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 monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
3,484				91,476		91,476	1
74				13,765		13,765	2
21,370				798,888		798,888	3
1,131				119,507		119,507	4
20,072				669,045		669,045	5
2,524				96,643		96,643	6
539				19,502		19,502	7
49					67,951	67,951	8
2,606,561				174,537,392		174,537,392	9
96,986				3,815,771		3,815,771	10
20,450				1,137,075		1,137,075	11
77,539				2,325,427		2,325,427	12
70,764				3,331,128		3,331,128	13
150				3,600		3,600	14
4,801,889	358	818	26,496,990	245,151,798	-21,796,058	249,852,730	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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 explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, 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 average billing demand in column (d), the average monthly 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, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) 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 monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
112,293				2,877,391		2,877,391	2
4,000				168,631		168,631	3
12,832				605,083		605,083	4
1,006				66,240		66,240	5
2,534				94,051		94,051	6
1,593				57,648		57,648	7
1,646,293			22,266,600	48,288,040	368,000	70,922,640	8
12,739			4,230,390	482,091		4,712,481	9
	358	818		-31,273		-31,273	10
5,561				277,179		277,179	11
3,770				190,759		190,759	12
857				38,859		38,859	13
6,635				332,681		332,681	14
4,801,889	358	818	26,496,990	245,151,798	-21,796,058	249,852,730	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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 explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, 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 average billing demand in column (d), the average monthly 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, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) 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 monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
12,983				693,382		693,382	1
3,650				181,823		181,823	2
13,800				717,611		717,611	3
998				91,443		91,443	4
292				20,997		20,997	5
141				6,912		6,912	6
711				34,856		34,856	7
1,604				78,618		78,618	8
				5		5	9
5,001				245,046		245,046	10
964				47,222		47,222	11
226				11,087		11,087	12
6,041				295,994		295,994	13
644				31,569		31,569	14
4,801,889	358	818	26,496,990	245,151,798	-21,796,058	249,852,730	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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 explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, 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 average billing demand in column (d), the average monthly 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, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) 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 monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
11,406				430,739		430,739	1
							2
11,622				1,857,895		1,857,895	3
					-22,232,009	-22,232,009	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,801,889	358	818	26,496,990	245,151,798	-21,796,058	249,852,730	

Schedule Page: 326 Line No.: 1 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 1 Column: c
Contract for electric service dated 6/20/1973.

Schedule Page: 326 Line No.: 2 Column: c
Contract for electric service dated 11/1/1975 and 5/15/1976.

Schedule Page: 326 Line No.: 3 Column: c
Contract for electric service dated 1/1/1997.

Schedule Page: 326 Line No.: 4 Column: c
Contract for electric service dated 1/1/1996.

Schedule Page: 326 Line No.: 5 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 5 Column: c
Contract for Test and Excess Energy Purchase and Sale Agreement between South Carolina Electric & Gas Company and Columbia Energy LLC dated as of 1/17/2004.

Schedule Page: 326 Line No.: 6 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 6 Column: c
Contract for electric service dated 5/1/1984.

Schedule Page: 326 Line No.: 7 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 7 Column: c
Various agreements for purchased power from customers pursuant to the Company's PR-1 (Small Power Production, Cogeneration) Rate Schedule.

Schedule Page: 326 Line No.: 8 Column: c
Docket Nos. ER01-1043-000 and ER03-237-000.

Schedule Page: 326 Line No.: 8 Column: l
Barter arrangement for transmission ancillary services 1,2,5 and 6.

Schedule Page: 326 Line No.: 9 Column: a
Affiliated Company

Schedule Page: 326 Line No.: 9 Column: c
FERC Electric Rate Schedule No. 1, Schedule 8 Billing Format - Cost of Service Tariff Docket Nos. ER85-204-007 and ER85-603-005.

Schedule Page: 326 Line No.: 10 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 10 Column: c
FERC Electric Rate Schedule No. 1, Docket No. ER10-2712.

Schedule Page: 326 Line No.: 11 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 11 Column: c
Tariff No. 5, Docket No. ER12-2322.

Schedule Page: 326 Line No.: 12 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 12 Column: c
FERC Electric Tariff Volume No. 3, Docket No. ER14-1625.

Schedule Page: 326 Line No.: 13 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 13 Column: c

Tariff No. 4, Docket No. ER17-56

Schedule Page: 326 Line No.: 14 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 14 Column: c

International Swaps and Derivatives Association (ISDA) Agreement effective 9/1/2005.

Schedule Page: 326.1 Line No.: 2 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 2 Column: c

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 6/1/2003.

Schedule Page: 326.1 Line No.: 3 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 3 Column: c

Tariff #1, Docket No. ER10-2778.

Schedule Page: 326.1 Line No.: 4 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 4 Column: c

Tariff #4, Docket No. ER10-2881.

Schedule Page: 326.1 Line No.: 5 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 5 Column: c

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2004.

Schedule Page: 326.1 Line No.: 6 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 6 Column: c

FERC Electric Rate Schedule No. 42.

Schedule Page: 326.1 Line No.: 7 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 7 Column: c

FERC Electric Rate Schedule No. 29.

Schedule Page: 326.1 Line No.: 8 Column: c

Tariff #1, Docket No. ER10-1892.

Schedule Page: 326.1 Line No.: 8 Column: l

Scheduling charges.

Schedule Page: 326.1 Line No.: 9 Column: a

Termination requires a 4-year written notice by either party to terminate the agreement. Written notice for termination presented to Santee Cooper on 5/6/2016. The current effective date of termination is 5/6/2020.

Schedule Page: 326.1 Line No.: 9 Column: c

Contract for electric service dated 1/1/1997.

Schedule Page: 326.1 Line No.: 10 Column: c

Electric service provided under SCE&G's OATT Schedules 4 and 9.

Schedule Page: 326.1 Line No.: 10 Column: h

Over delivery of energy by Columbia Energy LLC.

Schedule Page: 326.1 Line No.: 10 Column: i
Under delivery of energy by Columbia Energy LLC.
Schedule Page: 326.1 Line No.: 11 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.1 Line No.: 11 Column: c
SCPSC Docket No. 2016-175-E, Order Nos. 2016-368, 2017-311 and 2017-546.
Schedule Page: 326.1 Line No.: 12 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.1 Line No.: 12 Column: c
SCPSC Docket No. 2016-177-E, Order Nos. 2016-369, 2017-312 and 2017-547.
Schedule Page: 326.1 Line No.: 13 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.1 Line No.: 13 Column: c
SCPSC Docket No. 2016-178-E, Order Nos. 2016-370 and 2017-315.
Schedule Page: 326.1 Line No.: 14 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.1 Line No.: 14 Column: c
SCPSC Docket No. 2016-181-E, Order Nos. 2016-372, 2017-316 and 2017-549.
Schedule Page: 326.2 Line No.: 1 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.2 Line No.: 1 Column: c
SCPSC Docket No. 2016-278-E, Order No. 2016-548.
Schedule Page: 326.2 Line No.: 2 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.2 Line No.: 2 Column: c
SCPSC Docket No. 2016-174-E, Order Nos. 2016-367, 2017-317 and 2017-552.
Schedule Page: 326.2 Line No.: 3 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.2 Line No.: 3 Column: c
SCPSC Docket No. 2016-182-E, Order Nos. 2016-373 and 2017-326.
Schedule Page: 326.2 Line No.: 4 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.2 Line No.: 4 Column: c
SCPSC Docket No. 2015-363-E, Order No. 2015-788.
Schedule Page: 326.2 Line No.: 5 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.2 Line No.: 5 Column: c
SCPSC Docket No. 2017-166-E, Order No. 2017-373.
Schedule Page: 326.2 Line No.: 6 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
Schedule Page: 326.2 Line No.: 6 Column: c
SCPSC Docket No. 2016-167-E, Order Nos. 2016-341, 2017-309 and 2017-310.
Schedule Page: 326.2 Line No.: 7 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 7 Column: c

SCPSC Docket No. 2016-171-E, Order Nos. 2016-364 and 2017-313.

Schedule Page: 326.2 Line No.: 8 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 8 Column: c

SCPSC Docket No. 2016-173-E, Order Nos. 2016-366, 2017-285 and 2017-286.

Schedule Page: 326.2 Line No.: 9 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 9 Column: c

SCPSC Docket No. 2015-378-E, Order Nos. 2015-812 and 2017-289.

Schedule Page: 326.2 Line No.: 10 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 10 Column: c

SCPSC Docket No. 2015-380-E, Order Nos. 2015-814, 2016-324, 2017-293 and 2017-548.

Schedule Page: 326.2 Line No.: 11 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 11 Column: c

SCPSC Docket No. 2016-169-E, Order Nos. 2016-343, 2017-287, and 2017-288.

Schedule Page: 326.2 Line No.: 12 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 12 Column: c

SCPSC Docket No. 2015-379-E, Order Nos. 2015-813, 2017-318 and 2017-551.

Schedule Page: 326.2 Line No.: 13 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 13 Column: c

SCPSC Docket No. 2016-168-E, Order Nos. 2016-342, 2017-319, and 2017-550.

Schedule Page: 326.2 Line No.: 14 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.2 Line No.: 14 Column: c

SCPSC Docket No. 2016-179-E, Order Nos. 2016-371 and 2017-320.

Schedule Page: 326.3 Line No.: 1 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.3 Line No.: 1 Column: c

SCPSC Docket No. 2016-100-E, Order No. 2016-200.

Schedule Page: 326.3 Line No.: 3 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.3 Line No.: 3 Column: c

SCPSC Docket No. 2015-54-E, Order Nos. 2015-512 and 2015-765.

Schedule Page: 326.3 Line No.: 4 Column: l

Reflects amortization of previously deferred purchased power and capacity charges of $282,658 and $296,000 respectively per SCPSC Docket No. 2009-489-E.

Reflects the deferral of purchase power per SCPSC Docket No. 2009-489-E of($4,783,004).

Reflects the deferral of capacity purchases from Columbia Energy LLC per per SCPSC Docket No. 2013-276-E of ($13,631,159).

Reflects fuel expense of $6,124 for Company-owned fuel used by Columbia Energy LLC for generation.

Reflects the deferral of purchase power of ($4,402,628) pursuant to SCPSC Docket No. 2015-54-E under the Company's Distributed Energy Resources (DER) program.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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 the energy was received from and in column (c) the company or public 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 acronyms. Explain in a footnote any ownership interest in or affiliation the 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 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.

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 Classifi-cation (d)
1	Duke Energy Carolinas, LLC	Georgia Power Company	Duke Energy Carolinas, LLC	SFP
2				
3	The Energy Authority, Inc.	Georgia Power Company	South Carolina Public Service	
4			Authority	SFP
5				
6	The Energy Authority, Inc.	Georgia Power Company	South Carolina Public Service	
7			Authority	NF
8				
9	Southern Company Services, Inc.	Duke Energy Carolinas, LLC	Georgia Power Company	NF
10				
11	Southern Company Services, Inc.	Georgia Power Company	Duke Energy Carolinas, LLC	NF
12				
13	South Carolina Public Service	South Carolina Public Service	Central Electric Power Co-op	
14	Authority	Authority		FNO
15				
16	Southeastern Power Administration	Southeastern Power		
17		Administration		FNO
18				
19	City of Orangeburg	South Carolina Electric & Gas	City of Orangeburg	
20		Company		FNO
21				
22	Town of Winnsboro	South Carolina Electric & Gas	Town of Winnsboro	
23		Company		FNO
24				
25	Central Electric Power Co-op	South Carolina Public Service	Central Electric Power Co-op	
26		Authority		FNO
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), 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 (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
T5.S7,S1,S2	SOCO	DUK	306	3,079	3,018	1
						2
						3
T5.S7,S1,S2	SOCO	SC	48	1,127	1,104	4
						5
						6
T5.S8,S1,S2	SOCO	SC				7
						8
T5.S8,S1,S2	DUK	SOCO		38	37	9
						10
T5.S8,S1,S2	SOCO	DUK		30	29	11
						12
						13
T5. Attach H			588	298,137	289,456	14
						15
						16
T5. Attach H			216	20,136	19,434	17
						18
						19
T5. Attach H			1,594	859,723	834,683	20
						21
						22
T5. Attach H			123	61,395	60,192	23
						24
						25
T5. Attach H			81	29,996	29,408	26
						27
						28
						29
						30
						31
						32
						33
						34
			2,956	**1,273,661**	**1,237,361**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 to the billing demand reported in column (h). In column (l), provide revenues 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 rendered, including out of period adjustments. Explain in a footnote all 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 no monetary settlement was made, enter zero (11011) in column (n). Provide a 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 Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
45,825		2,036	47,861	1
				2
				3
4,253		254	4,507	4
				5
				6
2,078		92	2,170	7
				8
1,209		62	1,271	9
				10
281		13	294	11
				12
				13
2,072,289	73,388	98,989	2,244,666	14
				15
				16
668,078		67,951	736,029	17
				18
				19
4,823,492		563,879	5,387,371	20
				21
				22
376,466		43,961	420,427	23
				24
				25
243,332	3,175	11,611	258,118	26
				27
				28
				29
				30
				31
				32
				33
				34
8,237,303	**76,563**	**788,848**	**9,102,714**	

Schedule Page: 328 Line No.: 1 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 1 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 1 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 4 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 4 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 4 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 7 Column: h
Non-firm hourly billing demand of 222.
Schedule Page: 328 Line No.: 7 Column: i
Customer reserved transmission service but did not schedule service.
Schedule Page: 328 Line No.: 7 Column: j
Customer reserved transmission service but did not schedule service.
Schedule Page: 328 Line No.: 7 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 9 Column: h
Non-firm hourly billing demand of 156.
Schedule Page: 328 Line No.: 9 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 9 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 9 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 11 Column: h
Non-firm hourly billing demand of 30.
Schedule Page: 328 Line No.: 11 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 11 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 11 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 14 Column: e
Also includes Rate Schedules S1, S2 and S4 of Tariff.
Schedule Page: 328 Line No.: 14 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 14 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 14 Column: l
Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.
Schedule Page: 328 Line No.: 14 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 14 Column: n
Network transmission revenue.
Schedule Page: 328 Line No.: 16 Column: c
South Carolina Public Service Authority, Little River Electric Cooperative, Town of McCormick, City of Orangeburg and Town of Winnsboro.

Schedule Page: 328 Line No.: 17 Column: e

Also includes Rate Schedules S1, S2, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 17 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 17 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 17 Column: m

Sum of Ancillary Service 1, 2, 5 and 6 charges.

Schedule Page: 328 Line No.: 17 Column: n

Network transmission revenue.

Schedule Page: 328 Line No.: 20 Column: e

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 20 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 20 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 20 Column: m

Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 20 Column: n

Network transmission revenue.

Schedule Page: 328 Line No.: 23 Column: e

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 23 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 23 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 23 Column: m

Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 23 Column: n

Network transmission revenue.

Schedule Page: 328 Line No.: 26 Column: e

Also includes Rate Schedules S1, S2 and S4 of Tariff.

Schedule Page: 328 Line No.: 26 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 26 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 26 Column: l

Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.

Schedule Page: 328 Line No.: 26 Column: m

Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 26 Column: n

Network transmission revenue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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 Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Carolinas	FNS	5,019	4,903	15,124	-3,734	16,200	27,590
2	Adjustments						2,943,277	2,943,277
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		5,019	4,903	15,124	-3,734	2,959,477	2,970,867

Schedule Page: 332 Line No.: 1 Column: g

Scheduling, System Control and Dispatch	$ 362
Reactive Supply and Voltage Control	1,938
Regulation and Frequency Response	368
Operating Reserve - Spinning	790
Operating Reserve - Supplement	790
Other - Direct Assignment Charges	11,952
Total	$ 16,200

Schedule Page: 332 Line No.: 2 Column: g

Columbia Energy LLC Reactive Supply and Voltage Control (RSV) to SCE&G	$ 488,000
Reflects the amortization of transmission charges relating to the purchase of transmission services from Southern Company Services, Inc. pursuant to SCPSC Docket No. 2013-276-E.	2,290,191
Refund for penalty assessments and distributions in accordance with FERC Order Nos. 890 and 890-A and Southern Company Services, Inc. Open Access Transmission Tariff (OATT) for 2016.	(299)
True-up of surcharge for Southern Company Services, Inc. Open Access Transmission Tariff (OATT) for transmission service for 2016.	218.748
Refund from Southern Company Services, Inc. which was based on their adjusted 2016 true-up rates under the Open Access Transmission Tariff (OATT).	(52,416)
Duke Energy Carolinas, LLC refund calculated on Transmission Service for 2016.	(947)
Total	$2,943,277

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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	45,792
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,459,688
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	265,298
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Transportation and Other Power Operated Equipment	23,945
7	Travel excluding Meals	6,178
8	Meals	314
9	Computer Hardware and Software Maintenance	68,302
10	Utilities	18,381
11	Telephone Resource Usage	38,638
12	Director Fees and Expenses	1,669,482
13	Outside Services	20,536
14	Computer Resource Usage, Hardware, Software	
15	and Network Services	131,213
16	Company Payroll	170,090
17	Aircraft Transportation	40,019
18	Depreciation, Amortization and Property Tax Charges	
19	billed from SCANA Services	13,898,396
20	Postage	6,331
21	Research and Development Grant Amortization	100,000
22	Miscellaneous	55,141
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
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45		
46	TOTAL	18,017,744

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

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 8 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 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			6,052,331		6,052,331
2	Steam Production Plant	67,742,037				67,742,037
3	Nuclear Production Plant	21,135,839				21,135,839
4	Hydraulic Production Plant-Conventional	2,360,345				2,360,345
5	Hydraulic Production Plant-Pumped Storage	2,156,924				2,156,924
6	Other Production Plant	24,929,237				24,929,237
7	Transmission Plant	30,389,629				30,389,629
8	Distribution Plant	74,918,130				74,918,130
9	Regional Transmission and Market Operation					
10	General Plant	4,578,290				4,578,290
11	Common Plant-Electric	5,999,322		3,926,560		9,925,882
12	TOTAL	234,209,753		9,978,891		244,188,644

B. Basis for Amortization Charges

Electric Intangible Plant (Account 404) consists of the following:

Amortization of Saluda Hydro Project #516, Stevens Creek Project #2535, Neal Shoals Project #2315 and relicensing costs associated with VC Summer Nuclear Station. The charges were based on plant balances of Saluda - $793,257, Stevens Creek - $2,268,402 and Neal Shoals - $1,507,162. The associated costs of relicensing the VC Summer Nuclear Plant through 2042 is $8,564,832.

Amortization of a steam generator at cogeneration facility over the contractual term of the facility. The amortization is based on a gross plant amount of $11,144,060.

Data processing software costs of $64,108,771 are being amortized over the expected life of the software application.

Common Plant - Electric (Account 404):
The charges represent the amortization of data processing software of $129,364,888 over the expected life of the software.

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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							
13							
14							
15							
16							
17							
18							
19							
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21							
22							
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Schedule Page: 336 Line No.: 12 Column: a

Method of Determination of Depreciation Charges:

The Annual Provisions for Depreciation of Property, with the exception of major construction, are based on straight line rates applied to the prior month ending plant balances. The Annual Provision for Depreciation of major construction projects, if any, is computed based on the number of days that the plant was in service.

In addition to Depreciation Provisions provided by the application of the rates reported on this schedule in 2015, the Company also recognized $3,491,910 of electric and $701,053 of common depreciation related to vehicles, a well as, $5,655,498 of electric and $2,884,232 of common amortization related to software over their expected useful lives using the straight line method. See allocation of Common Plant on pages 356.1 and 356.2.

The Company also recognized amortization of a steam generator at a cogeneration facility over the contractual term of the facility. The amortization was based on a gross plant amount of $11,144,060.

Schedule Page: 336 Line No.: 13 Column: a

The Company completed this schedule in its 2015 Form No. 1 filing; therefore, in accordance with Instruction No. 3, the Company will complete the full Section C again in its Form No. 1 filing for 2020. There are no changes to report for the information required in Columns C through G. The information required in Columns C through G is only recalculated during full depreciation studies.

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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) relating to format cases 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 previous years.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	State assessment for the support of the				
2	Public Service Commission of South				
3	Carolina (SCPSC) and annual charges assessed				
4	by the Federal Energy Regulatory				
5	Commission (FERC).	5,052,203		5,052,203	
6					
7	Company labor, legal and miscellaneous				
8	expenses related to proceedings before the				
9	SCPSC.		60,311	60,311	
10					
11	Company labor, legal and miscellaneous				
12	expenses related to Dockets associated with				
13	Revisions and Updates for the Construction and				
14	Operation of a Nuclear Facility in				
15	Jenkinsville, SC related to proceedings before				
16	the SCPSC.		954,313	954,313	
17					
18	Company labor, legal, consulting and				
19	miscellaneous expenses related to proceedings				
20	before the FERC.		4,375	4,375	
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	TOTAL	5,052,203	1,018,999	6,071,202	

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REGULATORY COMMISSION EXPENSES (Continued)

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 column (f), (g), and (h) expenses incurred during 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				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
Electric	928	5,052,203					5
							6
							7
							8
Electric	928	60,311					9
							10
							11
							12
							13
							14
							15
Electric	928	954,313					16
							17
							18
							19
Electric	928	4,375					20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
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		6,071,202					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 & 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 & 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 & 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 & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed Internally	
2	(1) Generation	Coordination of EPRI and other R&D Activities (4 Items under $50,000)
3	(2) Transmission	Coordination of EPRI and other R&D Activities (4 Items under $50,000)
4	(3) Distribution	Coordination of EPRI and other R&D Activities (4 Items under $50,000)
5		
6		
7	B. Electric R,D and D Performed Externally	
8	(1) Research Support to EPRI	
9	Fossil Steam Plants and Combustion	
10	Turbine Programs	Coal Combustion Products - Environmental Issues
11		Fish Protection at Steam Electric Power Plants
12		Air Quality Assessment of Ozone, Particulate Matter, Visibility and
13		Deposition
14		Boiler and Turbine Steam and Cycle Chemistry
15		Combined Cycle HRSG and Balance of Plant
16		Balance of Plant Systems and Equipment
17		Operations Management and Technology
18		Water Management Technology
19	Transmission and Substation - Programs	
20		Structure and Sub-Grade Corrosion Management
21		Lightning Performance and Grounding of Transmission Lines
22		Line Design Tools and Practices for Construction and Maintenance
23		Polymer and Composite Overhead Transmission Insulators
24		Overhead Line Ratings and Increased Power Flow
25		High Temperature Operation of Overhead Lines
26		Asset Management Analytics for Overhead Transmission Lines
27		Technology Transfer for Underground Transmission
28		Transformer Life Management
29		Disconnect Switches, Arrestors and Ratings
30		Substation Physical Security and Intentional Electromagnetic
31		Interference (IEMI)
32		
33	Power Quality and Renewables Programs	
34		Integrating PQ Monitoring and Intelligent Applications to
35		Maximize System Performance
36		Strategic Intelligence and Analytics (Energy Storage)
37		Technology Transfer and Industry Coordination
38		

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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 & 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 & 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 & 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 & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Cyber Security - Programs	
2		Cyber Security and Privacy
3	Nuclear Power - Programs	
4		Nuclear Power
5		Steam Turbines, Generators and Auxiliary Systems
6	Nuclear - Supplemental Projects	
7		Flexible Operations Program
8		Pressurized Water Reactor Steam Generator
9		Management Program
10		Pressurized Water Reactor Materials
11		Reliability Program
12		Fuel Reliability Program
13		Fuel Works / Cask Loader Users Group
14		Standardized Task Evaluations for Portable Qualifications
15		External Hazards Data Collection
16		Advanced Nuclear Technology Program
17		LLW Technical Strategy Group
18		Radiation Management and Source Team
19		SMART chemWorks Users Groups
20		Pressurized Water Reactor Technical Strategy Group
21		FTREX
22		
23	(4) Research Support to Others (Classify):	
24	Clemson University Electric	
25	Power Research Association	
26	Georgia Tech Research Corporation National	
27	Electric Energy Testing and Research	
28	Applications Center	
29	Southeast Coastal Wind Coalition	
30	Smart Electric Power Alliance	
31	Marketing Research	
32		
33	Total Cost Incurred	
34		
35		
36		
37		
38		

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(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 & 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 & 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 & 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 &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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
47,811			47,811		2
14,461			14,461		3
10,236			10,236		4
					5
					6
					7
					8
					9
	57,457	930.2	57,457		10
	69,511	930.2	69,511		11
					12
	73,751	930.2	73,751		13
	45,180	930.2	45,180		14
	81,384	930.2	81,384		15
	17,763	930.2	17,763		16
	49,245	930.2	49,245		17
	65,818	930.2	65,818		18
					19
	10,484	930.2	10,484		20
	18,358	930.2	18,358		21
	14,754	930.2	14,754		22
	17,041	930.2	17,041		23
	11,711	930.2	11,711		24
	13,383	930.2	13,383		25
	9,480	930.2	9,480		26
	9,422	930.2	9,422		27
	36,374	930.2	36,374		28
	10,185	930.2	10,185		29
					30
	12,367	930.2	12,367		31
					32
					33
					34
	41,239	930.2	41,239		35
	14,474	930.2	14,474		36
	14,401	930.2	14,401		37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(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 & 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 & 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 & 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 &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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
	69,525		69,525		2
					3
	587,328	524	587,328		4
	55,901	524	55,901		5
					6
	22,000	107	22,000		7
					8
	68,833	524	68,833		9
					10
	159,000	524	159,000		11
	107,438	524	107,438		12
	12,000	186, 524	12,000		13
	11,927	524	11,927		14
	10,000	182.3	10,000		15
	137,500	107	137,500		16
	17,000	524	17,000		17
	17,000	524	17,000		18
	20,000	524	20,000		19
	7,333	524	7,333		20
	26,667	524	26,667		21
					22
					23
					24
	30,000	930.2	30,000		25
					26
					27
	104,000	930.2	104,000		28
	5,000	921	5,000		29
	25,000	921	25,000		30
	22,289	930.2	22,289		31
					32
72,508	2,209,523		2,282,031		33
					34
					35
					36
					37
					38

Schedule Page: 352 Line No.: 2 Column: e

408.1 / 517 / 551 / 920/ 921 / 923 / 926 / 931

Schedule Page: 352 Line No.: 3 Column: e

408.1 / 920 / 921 / 923 / 926 / 931

Schedule Page: 352 Line No.: 4 Column: e

408.1 / 588 / 920 / 921 / 923 / 926 / 931

Schedule Page: 352.1 Line No.: 2 Column: e

107 / 121 / 182.3 / 426.5 / 506 / 524 / 532 / 562 / 588 / 902 / 903 / 916 / 921

Schedule Page: 352.1 Line No.: 35 Column: a

In addition to the activity reported herein, the Company has also claimed significant tax-defined research and experimentation deductions under Internal Revenue Code Section 174 and credits under Internal Revenue Code Section 41 related to the design and construction activities of V.C. Summer Nuclear Station Units 2 and 3. See Note 5 to the financial statements for additional details.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	50,980,726		
4	Transmission	4,899,835		
5	Regional Market			
6	Distribution	6,129,585		
7	Customer Accounts	17,850,212		
8	Customer Service and Informational	2,512,682		
9	Sales	948,243		
10	Administrative and General	29,702,264		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	113,023,547		
12	Maintenance			
13	Production	28,325,314		
14	Transmission	2,222,218		
15	Regional Market			
16	Distribution	10,330,947		
17	Administrative and General	1,532,290		
18	TOTAL Maintenance (Total of lines 13 thru 17)	42,410,769		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	79,306,040		
21	Transmission (Enter Total of lines 4 and 14)	7,122,053		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	16,460,532		
24	Customer Accounts (Transcribe from line 7)	17,850,212		
25	Customer Service and Informational (Transcribe from line 8)	2,512,682		
26	Sales (Transcribe from line 9)	948,243		
27	Administrative and General (Enter Total of lines 10 and 17)	31,234,554		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	155,434,316	21,599,329	177,033,645
29	Gas			
30	Operation			
31	Production-Manufactured Gas	177,306		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	11,092,868		
37	Customer Accounts	3,349,316		
38	Customer Service and Informational	582,969		
39	Sales	2,953,696		
40	Administrative and General	5,877,175		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	24,033,330		
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			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,732,028		
49	Administrative and General	159,554		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,891,582		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	177,306		
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)	14,824,896		
58	Customer Accounts (Line 37)	3,349,316		
59	Customer Service and Informational (Line 38)	582,969		
60	Sales (Line 39)	2,953,696		
61	Administrative and General (Lines 40 and 49)	6,036,729		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	27,924,912	3,714,409	31,639,321
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	183,359,228	25,313,738	208,672,966
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	76,197,474	7,201,961	83,399,435
69	Gas Plant	6,150,476	1,202,680	7,353,156
70	Other (provide details in footnote):		814,291	814,291
71	TOTAL Construction (Total of lines 68 thru 70)	82,347,950	9,218,932	91,566,882
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,384,840	1,126,206	5,511,046
74	Gas Plant	691,176	48,656	739,832
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,076,016	1,174,862	6,250,878
77	Other Accounts (Specify, provide details in footnote):			
78	Non Utility Property		841,380	841,380
79	Non Operating Expenses	3,505,256	1,451,676	4,956,932
80	Other Work In Progress	1,990,705	316,306	2,307,011
81	Other Balance Sheet Payroll	7,742,924	1,504,273	9,247,197
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	13,238,885	4,113,635	17,352,520
96	TOTAL SALARIES AND WAGES	284,022,079	39,821,167	323,843,246

Schedule Page: 354 Line No.: 70 Column: d

Common Plant

Schedule Page: 354 Line No.: 81 Column: d

DSM Deferrals, Regulatory Assets, PSI Accounts, Stores Expense and Temporary Facilities.

Schedule Page: 354 Line No.: 96 Column: d

Report totals do not include severance accruals recorded to account 920 - Administrative and General Salaries related to the abandonment of the V.C. Summer Unit 2 and Unit 3 Nuclear Project.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 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 order of the Commission or other authorization.

(1) and (2) See pages 356.1 and 356.2

(3) Common Utility Plant Expenses are not segregated, but charged to utility departments on a functional basis. South Carolina Electric & Gas Company owns all of the Common Utility Plant of SCANA Corporation. Other subsidiaries of SCANA Corporation that benefit from the use of Common Utility Plant are charged directly by South Carolina Electric & Gas Company for their proportionate share of the related expenses.

(4) July 24, 1948

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 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 order of the Commission or other authorization.

Common Utility Plant In Service	Balance End of Year
118-603 Misc Intangible Plant	$129,364,888
118-689 Land and Land Rights	18,841,171
118-690 Structures and Improvements	180,125,838
118-691 Office Furniture and Equipment	10,631,979
118-692 Transportation Equipment	6,162,829
118-694 Tools, Shop and Garage Equipment	1,958,698
118-695 Laboratory Equipment	147,838
118-696 Power-Operated Equipment	4,890,972
118-697 Communication Equipment	6,724,174
118-698 Miscellaneous Equipment	6,321,957
118-699 ARC Common Gen Plant	2,344,248
Total	$367,514,592

Note: Common Plant in service consists of land and buildings devoted jointly to all utility operations, such as general office buildings, storerooms and repair shops and equipment therein. Also, software and transportation equipment used jointly is thus classifed.

Construction Work in Progress - Common Utility Plant

Description of Project	Balance End of Year
Computer Telephony Integration Replacement	$ 658,571
Other Projects < $500K	1,440,048
Total	$ 2,098,619

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 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 order of the Commission or other authorization.

Common Plant in Service and Depreciation Reserve
Allocable to Utility Departments

Common Utility	Total (a)	Electric (b)	Gas (c)
Plant Allocable to Utility Departments (1)	$367,514,592	$331,645,168	$35,869,424
Less:			
Common Depreciable Reserve Allocable to Utility Departments (2)	163,184,706	147,257,879	15,926,827
Net Common Plant Allocable to Utility Departments	$204,329,886	$184,387,289	$19,942,597

(1) This allocation is based on functional use by Departments.
Percentage:Electric 90.24% and Gas 9.76%

(2) This allocation is based on functional use by Departments of common depreciable property.
Percentages are the same as in note (1).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
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36					
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43					
44					
45					
46	TOTAL				

Schedule Page: 397 Line No.: 2 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 2 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 2 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 2 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: e
No activity during reported period.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) 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)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			362	4,721	MW	104,615
2	Reactive Supply and Voltage			489,938	4,721	MW	288,423
3	Regulation and Frequency Response			368	1,717	MW	79,934
4	Energy Imbalance	116	MWH	-3,734	3,178	MWH	76,563
5	Operating Reserve - Spinning			790	1,933	MW	128,952
6	Operating Reserve - Supplement			790	1,933	MW	187,490
7	Other			2,467,229	1,175	MWH	31,273
8	Total (Lines 1 thru 7)	116		2,955,743	19,378		897,250

Schedule Page: 398 Line No.: 1 Column: b

Reference footnote Line No.1, Column D for detail on number of units.

Schedule Page: 398 Line No.: 1 Column: c

Reference footnote Line No.1, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 1 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 1	.059292	% Load Ratio Share	$ 362

Schedule Page: 398 Line No.: 2 Column: b

Reference footnote Line No.2, Column D for detail on number of units.

Schedule Page: 398 Line No.: 2 Column: c

Reference footnote Line No.2, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 2 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 2	.059292	% Load Ratio Share	$ 1,938
Columbia Energy LLC			
Reactive Supply and Voltage			
Control to SCEG	Flat Rate	Flat Rate	488,000
Total			$ 489,938

Schedule Page: 398 Line No.: 3 Column: b

Reference footnote Line No.3, Column D for detail on number of units.

Schedule Page: 398 Line No.: 3 Column: c

Reference footnote Line No.3, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 3 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 3	.059292	% Load Ratio Share	$ 368

Schedule Page: 398 Line No.: 4 Column: b

Reference footnote Line No.4, Column D for detail on number of units.

Schedule Page: 398 Line No.: 4 Column: c

Reference footnote Line No.4, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 4 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 4	116	MWH	($ 3,734)

Schedule Page: 398 Line No.: 4 Column: e

Energy Imbalance breakdown by MWH:

Net Band 1	Over Supplied	Under Supplied
2375	401	402

Schedule Page: 398 Line No.: 4 Column: g

Energy Imbalance breakdown by dollar amount:

Net Band 1	Over Supplied	Under Supplied *
$76,283	($11,896)	$12,176

* Reported value for Under Supplied is net of Energy Imbalance Penalties credited to users of the transmission system.

Schedule Page: 398 Line No.: 5 Column: b

Reference footnote Line No.5, Column D for detail on number of units.

Schedule Page: 398 Line No.: 5 Column: c

Reference footnote Line No.5, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 5 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 5	.059292	% Load Ratio Share	$ 790

Schedule Page: 398 Line No.: 6 Column: b

Reference footnote Line No.6, Column D for detail on number of units.

Schedule Page: 398 Line No.: 6 Column: c

Reference footnote Line No.6, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 6 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 6	.059292	% Load Ratio Share	$ 790

Schedule Page: 398 Line No.: 7 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Direct Assignment Charges and Other Miscellaneous Adjustments.			$ 11,952
Reflects the amortization of transmission charges relating to the purchase of transmission services from Southern Company Services, Inc. pursuant to SCPSC Docket No. 2013-276-E.			2,290,191
Refund for penalty assessments and distributions in accordance with FERC Order Nos. 890 and 890-A and Southern Company Services, Inc. Open Access Transmission Tariff(OATT) for 2016.			(299)
True-up of surcharge for Southern Company Services, Inc. Open Access Transmission Tariff(OATT)for transmission service for 2016.			218,748
Refund from Southern Company Services, Inc. which was based on their adjusted 2016 true-up rates under the Open Access Transmission Tariff (OATT).			(52,416)
Duke Energy Carolinas, LLC refund calculated on Transmission Service for 2016.			(947)
Total			$2,467,229

Schedule Page: 398 Line No.: 7 Column: e

Generator Imbalance breakdown by MWH:

Net Band 1	Over Delivered	Under Delivered
67	354	754

Schedule Page: 398 Line No.: 7 Column: g

Generator Imbalance breakdown by dollar amount:

Net Band 1	Over Delivered	Under Delivered*
$ 2,500	($10,215)	$38,988

* Reported value for Under Deliveries is net of Generator Imbalance Penalties credited to users of the transmission system.

Schedule Page: 398 Line No.: 8 Column: e

Total is not meaningful due to the summation of dissimilar units of measure.

Schedule Page: 398 Line No.: 8 Column: g

Ancillary Services revenue reported on this schedule is reported as necessary in other supporting schedules within this Form 1 filing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

NAME OF SYSTEM:

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)
1	January	4,933	9	800	4,677	256				
2	February	3,582	10	800	3,378	204				
3	March	4,417	16	800	4,181	236				
4	Total for Quarter 1				12,236	696				
5	April	4,235	28	1700	4,047	188				
6	May	4,366	20	1800	4,177	189				
7	June	4,550	15	1600	4,320	230				
8	Total for Quarter 2				12,544	607				
9	July	5,002	14	1600	4,760	242				
10	August	5,177	18	1700	4,938	239				
11	September	4,528	28	1600	4,305	223				
12	Total for Quarter 3				14,003	704				
13	October	4,288	12	1700	4,081	207				
14	November	3,811	20	800	3,625	186				
15	December	4,014	29	900	3,812	202				
16	Total for Quarter 4				11,518	595				
17	Total Year to Date/Year				50,301	2,602				

Schedule Page: 400 Line No.: 1 Column: d

All times shown are in Hour Ending (HE) format.

Schedule Page: 400 Line No.: 1 Column: e

For all values shown in column (e):

The Company utilizes grandfathered service for its retail customers and has not executed a network integration transmission service agreement under the OATT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports 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)
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	21,963,071
3	Steam	6,914,656	23	Requirements Sales for Resale (See instruction 4, page 311.)	914,668
4	Nuclear	4,610,254	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,330
5	Hydro-Conventional	160,730	25	Energy Furnished Without Charge	9
6	Hydro-Pumped Storage	381,967	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	155,953
7	Other	7,730,456	27	Total Energy Losses	1,037,021
8	Less Energy for Pumping	537,497	28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	24,072,052
9	Net Generation (Enter Total of lines 3 through 8)	19,260,566			
10	Purchases	4,801,889			
11	Power Exchanges:				
12	Received	358			
13	Delivered	818			
14	Net Exchanges (Line 12 minus line 13)	-460			
15	Transmission For Other (Wheeling)				
16	Received	352,543			
17	Delivered	342,486			
18	Net Transmission for Other (Line 16 minus line 17)	10,057			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	24,072,052			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,912,132		4,457	9	800
30	February	1,601,220	31	3,600	10	800
31	March	1,832,417		4,101	16	800
32	April	1,794,072		3,720	28	1700
33	May	2,034,903		4,000	16	1700
34	June	2,204,680	1,358	4,364	15	1600
35	July	2,458,968		4,613	14	1600
36	August	2,423,882		4,701	18	1700
37	September	2,066,203		4,303	28	1600
38	October	1,947,880		4,059	10	1600
39	November	1,777,164		3,339	20	800
40	December	2,018,531		3,949	11	800
41	TOTAL	24,072,052	1,389			

Schedule Page: 401 Line No.: 16 Column: b

Certain transactions reported in account 456.1 - Transmission of Electricity for Others were supplied with generation from SCE&G’s system. The MWH supporting these transactions are included in SCE&G’s net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,273,661	1,237,361
Page 401a	352,543	342,486
Difference	921,118	894,875

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 20	859,723	834,683
Page 329 line 23	61,395	60,192
Total	921,118	894,875

Schedule Page: 401 Line No.: 17 Column: b

Certain transactions reported in account 456.1 - Transmission of Electricity for Others were supplied with generation from SCE&G’s system. The MWH supporting these transactions are included in SCE&G’s net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,273,661	1,237,361
Page 401a	352,543	342,486
Difference	921,118	894,875

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 20	859,723	834,683
Page 329 line 23	61,395	60,192
Total	921,118	894,875

Schedule Page: 401 Line No.: 29 Column: f

All times shown in column (f) are in Hour Ending (HE) format.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	Plant Name: *V.C. Summer (2/3rds)* (b)			Plant Name: *Urquhart* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	PWR			Conventional		
3	Year Originally Constructed	1984			1953		
4	Year Last Unit was Installed	1984			1955		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	686.40			100.00		
6	Net Peak Demand on Plant - MW (60 minutes)	664			100		
7	Plant Hours Connected to Load	7079			1950		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	661			96		
10	When Limited by Condenser Water	647			95		
11	Average Number of Employees	705			62		
12	Net Generation, Exclusive of Plant Use - KWh	4610254000			110033000		
13	Cost of Plant: Land and Land Rights	880612			2616353		
14	Structures and Improvements	329317362			16816234		
15	Equipment Costs	1011659408			101681805		
16	Asset Retirement Costs	22893826			10811187		
17	Total Cost	1364751208			131925579		
18	Cost per KW of Installed Capacity (line 17/5) Including	1988.2739			1319.2558		
19	Production Expenses: Oper, Supv, & Engr	11205587			95545		
20	Fuel	44074146			3856757		
21	Coolants and Water (Nuclear Plants Only)	3305652			0		
22	Steam Expenses	7690720			228488		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	3123002			187039		
26	Misc Steam (or Nuclear) Power Expenses	41638023			1035026		
27	Rents	0			0		
28	Allowances	0			-45584		
29	Maintenance Supervision and Engineering	-664682			11595		
30	Maintenance of Structures	3383970			19405		
31	Maintenance of Boiler (or reactor) Plant	17497562			314213		
32	Maintenance of Electric Plant	4777174			301949		
33	Maintenance of Misc Steam (or Nuclear) Plant	11124531			518195		
34	Total Production Expenses	147155685			6522628		
35	Expenses per Net KWh	0.0319			0.0593		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear			Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Grams			Barrels	MCF	
38	Quantity (Units) of Fuel Burned	725189	0	0	35	1193869	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	63738	0	0	137272	1032	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	203.093	3.235	0.000
41	Average Cost of Fuel per Unit Burned	60.780	0.000	0.000	111.367	3.235	0.000
42	Average Cost of Fuel Burned per Million BTU	0.954	0.000	0.000	19.316	3.133	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.035	0.000
44	Average BTU per KWh Net Generation	10.026	0.000	0.000	0.000	11200.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Cope* (b)			Plant Name: *Parr #1 & 2* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Package		
3	Year Originally Constructed	1996			1970		
4	Year Last Unit was Installed	1996			1970		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	417.36			39.10		
6	Net Peak Demand on Plant - MW (60 minutes)	418			30		
7	Plant Hours Connected to Load	7760			86		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	415			34		
10	When Limited by Condenser Water	415			27		
11	Average Number of Employees	68			0		
12	Net Generation, Exclusive of Plant Use - KWh	2384567000			1488000		
13	Cost of Plant: Land and Land Rights	3223719			9794		
14	Structures and Improvements	81856069			374752		
15	Equipment Costs	460467188			7312817		
16	Asset Retirement Costs	2257792			0		
17	Total Cost	547804768			7697363		
18	Cost per KW of Installed Capacity (line 17/5) Including	1312.5474			196.8635		
19	Production Expenses: Oper, Supv, & Engr	240542			0		
20	Fuel	81343885			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	10669			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2356467			0		
26	Misc Steam (or Nuclear) Power Expenses	2086234			0		
27	Rents	0			0		
28	Allowances	-97732			0		
29	Maintenance Supervision and Engineering	22462			0		
30	Maintenance of Structures	121256			0		
31	Maintenance of Boiler (or reactor) Plant	2635316			0		
32	Maintenance of Electric Plant	146939			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	2305552			0		
34	Total Production Expenses	91171590			0		
35	Expenses per Net KWh	0.0382			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas	Oil			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	MCF	Barrels			
38	Quantity (Units) of Fuel Burned	869994	1553382	3203	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12245	1033	137272	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	83.129	2.798	77.916	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	83.484	2.798	74.650	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.409	2.710	12.948	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.032	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9607.000	0.000	0.000	0.000	0.000	0.000

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Hagood #5* (b)			Plant Name: *Hagood #6* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	2000			1981		
4	Year Last Unit was Installed	2000			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	27.40			27.94		
6	Net Peak Demand on Plant - MW (60 minutes)	22			23		
7	Plant Hours Connected to Load	296			436		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	21			21		
10	When Limited by Condenser Water	18			20		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	4315000			7553000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	350422			683139		
15	Equipment Costs	7473187			9591187		
16	Asset Retirement Costs	0			0		
17	Total Cost	7823609			10274326		
18	Cost per KW of Installed Capacity (line 17/5) Including	285.5332			367.7282		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Urquhart #2 Peaking* (b)			Plant Name: *Urquhart #3 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	16.32			16.32		
6	Net Peak Demand on Plant - MW (60 minutes)	12			12		
7	Plant Hours Connected to Load	31			35		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	17			15		
10	When Limited by Condenser Water	14			12		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	178000			198000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	403542			394180		
15	Equipment Costs	1974149			2731706		
16	Asset Retirement Costs	0			0		
17	Total Cost	2377691			3125886		
18	Cost per KW of Installed Capacity (line 17/5) Including	145.6919			191.5371		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Coit #1 Peaking* (b)			Plant Name: *Coit #2 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.64			19.64		
6	Net Peak Demand on Plant - MW (60 minutes)	18			14		
7	Plant Hours Connected to Load	34			71		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	18			18		
10	When Limited by Condenser Water	14			12		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	315000			486000		
13	Cost of Plant: Land and Land Rights	35665			28094		
14	Structures and Improvements	97134			84743		
15	Equipment Costs	3424865			2689608		
16	Asset Retirement Costs	0			0		
17	Total Cost	3557664			2802445		
18	Cost per KW of Installed Capacity (line 17/5) Including	181.1438			142.6907		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Williams Combined* (b)			Plant Name: *Boeing* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Solar Photovoltaic		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)				Full-Outdoor		
3	Year Originally Constructed				2011		
4	Year Last Unit was Installed				2011		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	54.00			2.60		
6	Net Peak Demand on Plant - MW (60 minutes)	60			0		
7	Plant Hours Connected to Load	179			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	2448000			0		
13	Cost of Plant: Land and Land Rights	0			339		
14	Structures and Improvements	613695			117179		
15	Equipment Costs	6989384			9245463		
16	Asset Retirement Costs	0			0		
17	Total Cost	7603079			9362981		
18	Cost per KW of Installed Capacity (line 17/5) Including	140.7978			3601.1465		
19	Production Expenses: Oper, Supv, & Engr	645			0		
20	Fuel	150834			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	106594			2189		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	4020			0		
30	Maintenance of Structures	3514			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	34322			48522		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	299929			50711		
35	Expenses per Net KWh	0.1225			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Barrels				
38	Quantity (Units) of Fuel Burned	46840	282	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1032	137272	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.115	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.115	70.430	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.018	12.216	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.062	0.221	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			0.00			0.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			0			0
13	Cost of Plant: Land and Land Rights			0			0
14	Structures and Improvements			0			0
15	Equipment Costs			0			0
16	Asset Retirement Costs			0			0
17	Total Cost			0			0
18	Cost per KW of Installed Capacity (line 17/5) Including			0			0
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			0			0
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			0			0
35	Expenses per Net KWh			0.0000			0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			0.00			0.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			0			0
13	Cost of Plant: Land and Land Rights			0			0
14	Structures and Improvements			0			0
15	Equipment Costs			0			0
16	Asset Retirement Costs			0			0
17	Total Cost			0			0
18	Cost per KW of Installed Capacity (line 17/5) Including			0			0
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			0			0
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			0			0
35	Expenses per Net KWh			0.0000			0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
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30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Wateree* (d)	Plant Name: *McMeekin* (e)	Plant Name: *Canadys* (f)	Line No.
Steam	Steam	Steam	1
Outdoor-Boiler	Semi-Outdoor	Outdoor-Boiler	2
1970	1958	1962	3
1971	1958	1967	4
771.80	293.76	0.00	5
720	222	0	6
7675	5540	0	7
0	0	0	8
684	125	0	9
684	125	0	10
99	49	1	11
3566446000	345141000	0	12
2119622	15668	5577715	13
139975169	22491625	0	14
765771552	168303362	0	15
-20055089	4286210	0	16
887811254	195096865	5577715	17
1150.3126	664.1369	0	18
1815403	509479	0	19
125263196	14993920	0	20
0	0	0	21
421943	1857063	0	22
0	0	0	23
0	0	0	24
2768171	795905	0	25
1805830	1530938	0	26
0	0	0	27
-158294	-45770	0	28
2315	38390	0	29
356847	241501	0	30
8639096	922578	0	31
445163	5911951	0	32
1280655	1600072	0	33
142640325	28356027	0	34
0.0400	0.0822	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Gas	Oil					36
Tons	Barrels		MCF	Barrels					37
1477735	24821	0	3629060	913	0	0	0	0	38
12484	137272	0	1030	137272	0	0	0	0	39
81.103	78.083	0.000	4.098	67.456	0.000	0.000	0.000	0.000	40
81.930	72.505	0.000	4.098	131.686	0.000	0.000	0.000	0.000	41
3.281	12.576	0.000	3.978	22.841	0.000	0.000	0.000	0.000	42
0.035	0.000	0.000	0.043	0.000	0.000	0.000	0.000	0.000	43
10412.000	0.000	0.000	10848.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Parr #3 & 4* (d)	Plant Name: *Parr Combined* (e)	Plant Name: *Hagood #4* (f)	Line No.
Gas Turbine		Gas Turbine	1
Package		Package	2
1971		1991	3
1971		1991	4
44.54	83.64	121.89	5
37	67	90	6
82	168	321	7
0	0	0	8
39	0	99	9
33	0	88	10
0	2	0	11
1821000	3309000	20267000	12
6057	15851	96047	13
515640	890392	3525303	14
4238109	11550926	34617539	15
0	0	-6093062	16
4759806	12457169	32145827	17
106.8659	148.9379	263.7282	18
0	65100	0	19
0	247366	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	117241	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	4595	0	29
0	18412	0	30
0	0	0	31
0	63884	0	32
0	0	0	33
0	516598	0	34
0.0000	0.1561	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	50894	169	0	0	0	0	38
0	0	0	1032	137272	0	0	0	0	39
0.000	0.000	0.000	4.444	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	4.444	127.352	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	4.305	22.089	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.069	0.582	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Hagood Combined* (d)	Plant Name: *Hardeeville Peaking* (e)	Plant Name: *Urquhart #1 Peaking* (f)	Line No.
	Gas Turbine	Gas Turbine	1
	Package	Package	2
	1968	1969	3
	1968	1969	4
177.23	16.32	19.64	5
135	0	10	6
1053	0	38	7
0	0	0	8
0	9	16	9
0	9	13	10
8	0	0	11
32135000	0	259000	12
96047	5261	0	13
4558864	57556	505613	14
51681913	3553212	2295162	15
-6093062	0	0	16
50243762	3616029	2800775	17
283.4947	221.5704	142.6057	18
29641	375	0	19
1831666	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
393274	66705	0	25
0	0	0	26
0	0	0	27
-3194	0	0	28
100323	3895	0	29
112170	0	0	30
0	0	0	31
94964	27172	0	32
0	0	0	33
2558844	98147	0	34
0.0796	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Oil								36
MCF	Barrels								37
340764	2319	0	0	0	0	0	0	0	38
1033	137272	0	0	0	0	0	0	0	39
4.765	75.177	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
4.765	90.737	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
4.612	15.738	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.052	0.228	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Urquhart #4 Peaking* (d)	Plant Name: *Urquhart Comb 1-4* (e)	Plant Name: *Urquhart Comb Cycle* (f)	Line No.
Gas Turbine		Combined Cycle	1
Package		Package	2
1999		2002	3
1999		2002	4
58.90	111.18	547.80	5
47	81	476	6
385	489	12238	7
0	0	0	8
49	0	484	9
48	0	458	10
0	3	0	11
14010000	14645000	2187207000	12
0	0	0	13
638354	1941689	5212487	14
24282881	31283898	258584481	15
0	0	0	16
24921235	33225587	263796968	17
423.1110	298.8450	481.5571	18
0	5660	504452	19
0	579176	61016465	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	45382	2742417	25
0	0	0	26
0	0	0	27
0	0	17	28
0	11914	3908	29
0	631	316388	30
0	0	0	31
0	757086	3797262	32
0	0	0	33
0	1399849	68380909	34
0.0000	0.0956	0.0313	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil		Gas	Oil		36
			MCF	Barrels		MCF	Barrels		37
0	0	0	152315	683	0	16651433	900	0	38
0	0	0	1033	137272	0	1032	137272	0	39
0.000	0.000	0.000	3.338	0.000	0.000	3.663	0.000	0.000	40
0.000	0.000	0.000	3.338	104.555	0.000	3.663	111.642	0.000	41
0.000	0.000	0.000	3.232	18.135	0.000	3.548	19.364	0.000	42
0.000	0.000	0.000	0.035	0.361	0.000	0.028	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Coit Combined* (d)	Plant Name: *Williams #1 Peaking* (e)	Plant Name: *Williams #2 Peaking* (f)	Line No.
	Gas Turbine	Gas Turbine	1
	Package	Package	2
	1972	1972	3
	1972	1972	4
39.27	27.00	27.00	5
32	30	30	6
105	90	89	7
0	0	0	8
0	26	26	9
0	20	14	10
0	0	0	11
801000	1504000	944000	12
63759	0	0	13
181877	573399	40296	14
6114473	3272575	3716809	15
0	0	0	16
6360109	3845974	3757105	17
161.9585	142.4435	139.1520	18
6599	0	0	19
96546	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
45609	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
1218	0	0	29
3730	0	0	30
0	0	0	31
143969	0	0	32
0	0	0	33
297671	0	0	34
0.3716	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Oil								36
MCF	Barrels								37
13224	312	0	0	0	0	0	0	0	38
1032	137272	0	0	0	0	0	0	0	39
4.457	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
4.457	120.746	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
4.320	20.943	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.081	0.539	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Kapstone Generator* (d)	Plant Name: *Jasper* (e)	Plant Name: *Major Maint. Accrual* (f)	Line No.
Steam	Combined Cycle		1
Outdoor - Boiler	Package		2
1999	2004		3
1999	2004		4
99.31	1001.70	0.00	5
87	938	0	6
8385	5718	0	7
0	0	0	8
85	924	0	9
85	852	0	10
0	35	0	11
508469041	5486584000	0	12
0	2737068	0	13
0	28210305	0	14
11144060	477316204	0	15
0	0	0	16
11144060	508263577	0	17
112.2149	507.4010	0	18
0	739395	0	19
23069905	139282828	0	20
0	0	0	21
14631491	0	0	22
0	0	0	23
0	0	0	24
0	2762024	-7205	25
0	1619	0	26
0	0	0	27
0	-15940	0	28
0	230471	0	29
0	893	0	30
0	-53	-480	31
0	15362843	-2025196	32
0	15776	-875669	33
37701396	158379856	-2908550	34
0.0741	0.0289	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	39553059	679	0	0	0	0	38
0	0	0	1031	137272	0	0	0	0	39
0.000	0.000	0.000	3.519	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.519	49.888	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.412	8.653	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.025	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
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0	0	0	32
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0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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0	0	0	32
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0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
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		0			0			0	21
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		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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0	0	0	32
0	0	0	33
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0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
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0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
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0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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0	0	0	33
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0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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0	0	0	26
0	0	0	27
0	0	0	28
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0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
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0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
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		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: f

In December 2012, the Company retired the 90MW Unit 1 at Canadys Station. In November 2013, the Company retired the remaining units, Unit 2 (115MW) and Unit 3 (180MW).

Schedule Page: 402 Line No.: 1 Column: b

SCE&G's portion (two-thirds) of jointly owned plant.

Instruction No. 12 - V. C. Summer Nuclear Station

(a) Nuclear fuel amortization, which is included in Production Expenses, is recorded using the units-of-production method. Normal operation and maintenance costs are charged to expenses as incurred with appropriate application of the accrual method of accounting. Pursuant to an order issued by the South Carolina Public Service Commission, estimated refueling outage operation and maintenance costs for the five outages scheduled Spring 2014 through Spring 2020 are being accrued over the 90 month period (January 2013 through June 2020) covered by these outages.

(b) Cost is recorded for nuclear fuel on the batch basis. At reload, the number of new assemblies required to complete the core requirement of 157 assemblies is designated as the new batch. All costs for this new batch are reported according to classification of component by batch number. Each batch consists of costs for U308, conversion, enrichment, fabrication, and allowance for funds used during construction.

(c) The V. C. Summer Nuclear Station is a Westinghouse PWR Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy tube cladding. The equilibrium cycle has approximately 65.5 metric tons of Uranium metal with a nominal U-235 enrichment of 4.6% to 4.8%. The reactor is licensed to allow operation of 2900 MWt.

Schedule Page: 403 Line No.: 5 Column: f

There are no remaining units in service. Therefore, no installed capacity is being reported for this plant.

Schedule Page: 403 Line No.: 18 Column: f

There are no remaining units in service and the only remaining cost (asset value) is land. Therefore, no "cost per KW installed capacity" is being reported for this plant.

Schedule Page: 402 Line No.: 28 Column: c

Allowance expenses offset by a gain from the sale of 485 NOX allowances.

Schedule Page: 403 Line No.: 28 Column: d

Allowance expenses offset by a gain from the sale of 1,720 NOX allowances.

Schedule Page: 403 Line No.: 28 Column: e

Allowance expenses offset by a gain from the sale of 487 NOX allowances.

Schedule Page: 403.1 Line No.: 2 Column: e

Parr Steam Plant functions in a combined cycle operation with four gas turbine peaking units and two heat recovery boilers. Production expenses and fuel data are for the entire operation. See column (e), lines 19-44 for combined data on Parr units.

Schedule Page: 402.1 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: d

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: e

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: f

Employees not specifically assigned to individual units.

Schedule Page: 402.1 Line No.: 28 Column: b

Allowance expenses offset by a gain from the sale of 1,079 NOX allowances.

Schedule Page: 402.2 Line No.: 11 Column: b

Employees not specifically assigned to individual units.

Schedule Page: 402.2 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: d

Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: e

Unattended-automatic.

Schedule Page: 403.2 Line No.: 11 Column: f

Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 28 Column: d

Allowance expenses offset by a gain from the sale of 34 NOX allowances.

Schedule Page: 402.3 Line No.: 11 Column: b

Employees not specifically assigned to individual units.

Schedule Page: 402.3 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: d

Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: e

Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: f

Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: b

Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: d

Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: e

Unattended-automatic.

Schedule Page: 403.4 Line No.: 11 Column: f

Unattended-automatic.

Schedule Page: 402.5 Line No.: -1 Column: c

This is a rooftop mounted solar electric generator that provides electricity exclusively for use by a large industrial customer. None of the output flows onto the grid.

Schedule Page: 403.5 Line No.: -1 Column: f

The major maintenance accrual represents an SCPSC approved (SCPSC Docket No. 2009-489-E) annual accrual of $18.4 million through 2025. The Company is allowed to collect $18.4 million through retail electric rates to offset expenditures relating to certain turbine maintenance. Under this mechanism, the Company records an annual expense accrual of $18.4 million and records any difference between actual expenses incurred and this accrual as a regulatory asset or liability as appropriate.

For the year ended December 31, 2017, the Company incurred actual expenses in the amount of $20.5 million for major maintenance that is subject to this accrual. Cumulative costs for turbine maintenance in excess of cumulative collections are classified as a regulatory asset on the balance sheet.

Schedule Page: 402.5 Line No.: 11 Column: b

Unattended-automatic.

Schedule Page: 403.5 Line No.: 11 Column: d

SCE&G receives shaft horsepower from Kapstone Charleston Kraft LLC, a biomass/coal cogeneration facility, to operate SCE&G's generator.

Schedule Page: 403.5 Line No.: 28 Column: e

Allowance expenses offset by a gain from the sale of 170 NOX allowances.

Schedule Page: 402 Line No.: 43 Column: c2

All fuels.

Schedule Page: 402 Line No.: 43 Column: d1

All fuels.

Schedule Page: 402 Line No.: 43 Column: e1

All fuels.

Schedule Page: 402 Line No.: 44 Column: c2

All fuels.

Schedule Page: 402 Line No.: 44 Column: d1

All fuels.

Schedule Page: 402 Line No.: 44 Column: e1

All fuels.

Schedule Page: 402.1 Line No.: 43 Column: b1

All fuels.

Schedule Page: 402.1 Line No.: 44 Column: b1

All fuels.

Schedule Page: 402.3 Line No.: 43 Column: f1

All fuels.

Schedule Page: 402.5 Line No.: 43 Column: e1

All fuels.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 1894 Plant Name: Parr (b)	FERC Licensed Project No. 516 Plant Name: Saluda (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1914	1930
4	Year Last Unit was Installed	1921	1971
5	Total installed cap (Gen name plate Rating in MW)	14.88	207.30
6	Net Peak Demand on Plant-Megawatts (60 minutes)	11	143
7	Plant Hours Connect to Load	8,697	8,150
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	12	200
10	(b) Under the Most Adverse Oper Conditions	7	200
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	47,117,000	51,487,000
13	Cost of Plant		
14	Land and Land Rights	608,755	6,202,950
15	Structures and Improvements	1,900,134	7,725,855
16	Reservoirs, Dams, and Waterways	4,971,998	354,675,505
17	Equipment Costs	5,303,272	18,472,465
18	Roads, Railroads, and Bridges	124,198	233,527
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	12,908,357	387,310,302
21	Cost per KW of Installed Capacity (line 20 / 5)	867.4971	1,868.3565
22	Production Expenses		
23	Operation Supervision and Engineering	67,270	272,210
24	Water for Power	0	0
25	Hydraulic Expenses	35,392	1,177,676
26	Electric Expenses	47,412	1,781
27	Misc Hydraulic Power Generation Expenses	40,314	147,324
28	Rents	0	0
29	Maintenance Supervision and Engineering	4,382	19,991
30	Maintenance of Structures	20	625
31	Maintenance of Reservoirs, Dams, and Waterways	1,814	74,344
32	Maintenance of Electric Plant	469,531	264,949
33	Maintenance of Misc Hydraulic Plant	3,154	10,003
34	Total Production Expenses (total 23 thru 33)	669,289	1,968,903
35	Expenses per net KWh	0.0142	0.0382

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 2535 Plant Name: Stevens Creek (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1914			3
1926			4
17.28	0.00	0.00	5
17	0	0	6
8,150	0	0	7
			8
10	0	0	9
8	0	0	10
3	0	0	11
44,037,000	0	0	12
			13
406,315	0	0	14
3,051,491	0	0	15
6,430,203	0	0	16
5,312,868	0	0	17
128,812	0	0	18
0	0	0	19
15,329,689	0	0	20
887.1348	0.0000	0.0000	21
			22
53,693	0	0	23
0	0	0	24
77,707	0	0	25
606	0	0	26
39,260	0	0	27
0	0	0	28
1,020	0	0	29
2,197	0	0	30
2,411	0	0	31
489,701	0	0	32
13,008	0	0	33
679,603	0	0	34
0.0154	0.0000	0.0000	35

Schedule Page: 406 Line No.: 1 Column: b

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: c

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: d

Operated under license from the Federal Energy Regulatory Commission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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 the 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."

Line No.	Item (a)	FERC Licensed Project No. 1984 Plant Name: Fairfield (b)
1	Type of Plant Construction (Conventional or Outdoor)	Outdoor
2	Year Originally Constructed	1978
3	Year Last Unit was Installed	1978
4	Total installed cap (Gen name plate Rating in MW)	587
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	582
6	Plant Hours Connect to Load While Generating	3,286
7	Net Plant Capability (in megawatts)	576
8	Average Number of Employees	28
9	Generation, Exclusive of Plant Use - Kwh	386,027,000
10	Energy Used for Pumping	537,497,000
11	Net Output for Load (line 9 - line 10) - Kwh	-151,470,000
12	Cost of Plant	
13	Land and Land Rights	22,147,163
14	Structures and Improvements	36,349,788
15	Reservoirs, Dams, and Waterways	74,710,719
16	Water Wheels, Turbines, and Generators	67,490,796
17	Accessory Electric Equipment	19,326,562
18	Miscellaneous Powerplant Equipment	6,544,291
19	Roads, Railroads, and Bridges	1,328,336
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	227,897,655
22	Cost per KW of installed cap (line 21 / 4)	388.2413
23	Production Expenses	
24	Operation Supervision and Engineering	261,425
25	Water for Power	
26	Pumped Storage Expenses	115,105
27	Electric Expenses	31,863
28	Misc Pumped Storage Power generation Expenses	372,393
29	Rents	
30	Maintenance Supervision and Engineering	162,636
31	Maintenance of Structures	87
32	Maintenance of Reservoirs, Dams, and Waterways	447,320
33	Maintenance of Electric Plant	1,712,553
34	Maintenance of Misc Pumped Storage Plant	77,975
35	Production Exp Before Pumping Exp (24 thru 34)	3,181,357
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	3,181,357
38	Expenses per KWh (line 37 / 9)	0.0082

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
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			36
			37
			38

Schedule Page: 408 Line No.: 38 Column: b

Required information per FERC Order No. 784, Docket No. AI14-1-000

Expenses per KWH of Generation and Pumping (Line37/(Line 9 + Line 10) = .0034

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 pumped storage plants of less 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, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro-Neal Shoals					
2	Hydro License					
3	Project #2315	1905	4.41	6.0	18,089,000	9,092,102
4						
5						
6						
7						
8						
9						
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11						
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46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 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, if the exhaust heat from 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.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
503	201,196		279,568			3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						39
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						41
						42
						43
						44
						45
						46

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 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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 substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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; or (4) underground construction If a transmission line has more than one type of supporting structure, 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 construction need not be distinguished from the remainder of the line.
6. 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 reported for the line designated; conversely, show in column (g) the pole miles of line on structures the 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 of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	115 KV System	Various	115.00	230.00	Various	102.00	15.57	
2	115 KV System	Various	115.00	115.00	Various	1,409.06	101.18	
3	46 KV System	Various	46.00	115.00	Various	43.81		
4	46 KV System	Various	46.00	46.00	Various	578.22	25.77	
5	33 KV System	Various	33.00	33.00	Various	63.62	3.29	
6	13.8 KV System	SPA	13.80	46.00	Various	0.34		1
7	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP	11.10		1
8	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP		2.90	2
9	230 KV System							
10	CEC Cola Energy	Fold-in	230.00	230.00	STEEL-SP	5.88		1
11	Canadys	Faber Place	230.00	230.00	Wood-H	36.43		1
12	Canadys	Faber Place #2	230.00	230.00	Wood-H	42.80		1
13	Canadys	Graniteville-SRP	230.00	230.00	Wood-H	0.08		1
14	Canadys	Sumter	230.00	230.00	Wood-H	32.00		1
15	Canadys	Urquhart	230.00	230.00	Wood-H	79.47		1
16	Canadys	Williams	230.00	230.00	Steel - SP	2.04		1
17	Canadys	Yemassee	230.00	230.00	Wood-H	30.30		1
18	Church Creek	Faber Place #2	230.00	230.00	Wood-H	3.97		1
19	Church Creek	Yemassee	230.00	230.00	Various	52.10		1
20	Cope	Orangeburg	230.00	230.00	STEEL-SP	22.05		2
21	Cope	Canadys	230.00	230.00	STEEL-SP	40.53		2
22	Denny Terrace	Lyles	230.00	230.00	STEEL-SP	2.68		2
23	Edenwood	Denny Terrace	230.00	230.00	Wood-H	12.16		1
24	Edenwood	McMeekin	230.00	230.00	Various	11.48		1
25	Edenwood	Tie	230.00	230.00	Wood-H	1.45		1
26	Edenwood	Owens Steel	230.00	230.00	STEEL-SP	0.41		1
27	Fairfield	Summer	230.00	230.00	Wood-H	2.79		1
28	Goose Creek	Ashley Phos.	230.00	230.00	Wood-H	3.10		1
29	Graniteville Sub #1	Graniteville Sub #2	230.00	230.00	STEEL	0.06		1
30	Graniteville	Urquhart	230.00	230.00	Wood-H	11.23		1
31	Hanahan	Bushy Park	230.00	230.00	Wood-H	10.50		1
32	Hopkins	Tap	230.00	230.00	STEEL-SP	2.84		1
33	Huron	Tap	230.00	230.00	Wood-H	0.11		1
34	Jasper	Yemassee#1	230.00	230.00	STEEL-SP	39.49		2
35	Jasper	Yemassee#2	230.00	230.00	STEEL-SP	39.27		2
36					TOTAL	3,278.91	190.58	95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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 substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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; or (4) underground construction If a transmission line has more than one type of supporting structure, 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 construction need not be distinguished from the remainder of the line.
6. 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 reported for the line designated; conversely, show in column (g) the pole miles of line on structures the 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 of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Jasper	Purrysburg(Santee)	230.00	230.00	STEEL-SP	1.24		2
2	Ladson	Ashley Phos.	230.00	230.00	Wood-H	4.60		1
3	Lake Murray	Saluda River #1	230.00	230.00	Steel-SP	6.38		2
4	Lyles	Saluda River #1	230.00	230.00	Steel-SP	4.13		2
5	Lyles	Saluda River #2	230.00	230.00	Steel-SP	0.59		2
6	McMeekin	Parr	230.00	230.00	Wood-H	16.66		1
7	Parr	Denny Terrace	230.00	230.00	Wood-H	21.96		1
8	Parr	Duke	230.00	230.00	Tower		10.90	1
9	Pepperhill	Mateeba	230.00	230.00	Wood-H	7.10		1
10	Pineland	Denny Terrace	230.00	230.00	Steel-SP	8.46		2
11	St. George	Ladson	230.00	230.00	Wood-H	33.00		1
12	St. George	Williams	230.00	230.00	Steel-SP	0.97		1
13	Summer	Denny Terrace	230.00	230.00	Wood-H	4.53		1
14	Summer	Parr #1	230.00	230.00	Wood-H	2.38		1
15	Summer	Parr #2	230.00	230.00	Wood-H	2.26		1
16	Summer	Graniteville	230.00	230.00	Wood-H	63.26		1
17	Summer	Pineland	230.00	230.00	Wood-H	26.83		1
18	Summer	Denny Terrace	230.00	230.00	Wood-H	26.26		1
19	Summerville	Tap	230.00	230.00	Wood-H		0.08	1
20	Timberlake	Tap	230.00	230.00	Wood-SP	8.41		1
21	Urquhart	Fold-in	230.00	230.00	Steel-H	9.55		1
22	VCS1	Killian	230.00	230.00	Steel-SP	3.36		1
23	VCS1	Killian	230.00	230.00	Steel-SP	38.66		2
24	VCS2	Lake Murray #1	230.00	230.00	Steel-SP		20.53	2
25	VCS2	Lake Murray #2	230.00	230.00	Steel-SP	22.74		2
26	Vogtle	SRP	230.00	230.00	Steel-H	17.10		1
27	Ward	Tie	230.00	230.00	Wood-H	0.07		1
28	Wateree	Denny Terrace	230.00	230.00	Wood-H	28.60		1
29	Wateree	Edenwood	230.00	230.00	Wood-H	27.80		1
30	Wateree	Sumter	230.00	230.00	Wood-H	0.86		1
31	Wateree	St. George	230.00	230.00	Wood-H	45.60		1
32	Wateree	Pineland	230.00	230.00	Wood-H	38.62		1
33	Wateree	Hercules	230.00	230.00	Wood-H	0.45		1
34	Wateree	Orangeburg	230.00	230.00	Wood-H	27.10		1
35	Wateree-Edenwd	Columbia	230.00	230.00	Steel-H		2.95	2
36					TOTAL	3,278.91	190.58	95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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 substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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; or (4) underground construction If a transmission line has more than one type of supporting structure, 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 construction need not be distinguished from the remainder of the line.
6. 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 reported for the line designated; conversely, show in column (g) the pole miles of line on structures the 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 of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Williams	Wateree	230.00	230.00	Wood-H	10.30		1
2	Williams	Canadys	230.00	230.00	Wood-H	9.60	0.70	1
3	Williams	Faber Place #1	230.00	230.00	Steel-SP	0.53		2
4	Williams	Faber Place #2	230.00	230.00	Tower-H	13.65	6.71	2
5	Williams	Tie	230.00	230.00	Concrete	0.08		1
6	Williams	DuPont	230.00	230.00	Wood-H	6.60		1
7	Yemassee	Burton	230.00	230.00	Steel-SP	21.31		2
8	Yemassee	Santee	230.00	230.00	Wood-H	2.93		2
9	Underground							
10	33 KV System					0.23		2
11	46 KV System					0.90		1
12	115 KV System					19.88		1
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,278.91	190.58	95

TRANSMISSION LINE STATISTICS (Continued)

7. 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 you do not include Lower voltage lines with higher voltage lines. If two or more transmission line 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 column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line 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 operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such 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 the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
Various	1,462,454	35,724,481	37,186,935					1
Various	39,185,297	376,558,589	415,743,886					2
Various	442,674	3,081,240	3,523,914					3
Various	2,380,207	43,065,126	45,445,333					4
Various	62,375	4,067,000	4,129,375					5
336mcm		31,047	31,047					6
336mcm								7
336mcm	4,930	638,577	643,507					8
	19,735,721	367,986,169	387,721,890					9
1272mcm								10
795mcm								11
795mcm								12
795mcm								13
795mcm								14
1272mcm								15
1272mcm								16
Various								17
1272mcm								18
1272mcm								19
795mcm								20
795mcm								21
1272mcm								22
1272mcm								23
Various								24
1272mcm								25
1272mcm								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
1272mcm								32
1272mcm								33
1272mcm								34
1272mcm								35
	82,193,325	908,474,747	990,668,072	144,252	6,422,530		6,566,782	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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 you do not include Lower voltage lines with higher voltage lines. If two or more transmission line 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 column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line 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 operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such 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 the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272mcm								1
795mcm								2
1272mcm								3
1272mcm								4
1272mcm								5
795mcm								6
795mcm								7
954mcm								8
Various								9
1272mcm								10
795mcm								11
1272mcm								12
1272mcm								13
1272mcm								14
1272mcm								15
1272mcm								16
1272mcm								17
1272mcm								18
1272mcm								19
1272mcm								20
1272mcm								21
1272mcm								22
1272mcm								23
1272mcm								24
1272mcm								25
795mcm								26
1272mcm								27
Various								28
1272mcm								29
1272mcm								30
1272mcm								31
1272mcm								32
1272mcm								33
795mcm								34
1272mcm								35
	82,193,325	908,474,747	990,668,072	144,252	6,422,530		6,566,782	36

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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 you do not include Lower voltage lines with higher voltage lines. If two or more transmission line 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 column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line 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 operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such 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 the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272mcm								1
1272mcm								2
1272mcm								3
1272mcm								4
1272mcm								5
1272mcm								6
1272mcm								7
1272mcm								8
								9
250mcm		16,443	16,443					10
750mcm		1,620,606	1,620,606					11
2250kcm	18,919,667	75,685,469	94,605,136					12
				144,252	6,422,530		6,566,782	13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	82,193,325	908,474,747	990,668,072	144,252	6,422,530		6,566,782	36

Schedule Page: 422 Line No.: 1 Column: h

Various

Schedule Page: 422 Line No.: 2 Column: h

Various

Schedule Page: 422 Line No.: 3 Column: h

Various

Schedule Page: 422 Line No.: 4 Column: h

Various

Schedule Page: 422 Line No.: 5 Column: h

Various

Schedule Page: 422 Line No.: 9 Column: l

Total capitalized cost of 230kV System.

Schedule Page: 422.2 Line No.: 13 Column: a

Reported costs in column (l) reflect total costs including balances recorded in Account 106 - Completed Construction not Classified. Columns (a) through (i) include statistical data related to unitized plant only.

Schedule Page: 422.2 Line No.: 13 Column: m

Operation expense includes Accounts 563 - Overhead Line Expenses and 564 - Underground Line Expenses.

Schedule Page: 422.2 Line No.: 13 Column: n

Maintenance expense includes Accounts 571 - Maintenance of Overhead Lines and 572 - Maintenance of Underground Lines.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OVERHEAD						
2	McMeekin	Lake Murray	0.59	Steel	15.00	2	2
3	Saluda Hydro	Lake Murray	0.90	Steel	7.00	1	1
4	Mercedes-Benz Vans	Fold-In	1.12	Steel	15.00	2	2
5	VCS2	Lake Murray #2	22.74	Steel	56.00	2	2
6	Denny Terrace	Lyles #1	2.68	Steel	12.00	2	2
7	VCS2	St George #2	22.85	Steel	6.00	2	2
8	Cainhoy	Hamlin	2.10	Steel	22.00	2	2
9	McMeekin	Dunbar	5.30	Steel	6.00	2	2
10	Wateree	Denny Terrace	2.88	Steel	5.00	2	2
11	Edenwood	Lake Murray	1.00	Steel	2.00	2	2
12	Wateree	Orangeburg	1.39	Steel	13.00	2	2
13	Parr	Midway #1	0.92	Steel	10.00	2	2
14	Parr	Midway #2	0.92	Steel	10.00	2	2
15	VCS1	Newport	2.46	Steel	20.00	1	1
16	VCS2	Graniteville	0.76	Steel	11.00	1	1
17	VCS2	Denny Terrace	1.50	Steel	19.00	1	1
18	Parr	Winnsboro #1	1.22	Steel	26.00	2	2
19	VCS2	St George #1	31.85	Steel	25.00	2	2
20	Canadys	Sumter Cpl Tie	9.84	Steel	8.00	1	1
21	Cainhoy	Mt Pleasant #1	2.46	Steel	21.00	2	2
22	Cainhoy	Mt Pleasant #2	1.92	Steel	20.00	1	1
23	Williams	Cainhoy #2	0.74	Steel	39.00	2	2
24	VCS2	St George #2	31.85			2	2
25	VCS2	Lake Murray #1	-20.53	Various	13.00	2	2
26	Denny Terrace	Lyles #2	-2.67	Various	2.00	1	1
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		126.79		383.00	43	43

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground 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 characteristic.

CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Line No.
									1
1272	ACSR		115		418,180	215,394		633,574	2
1272	ACSR		115		339,512	289,660		629,172	3
1272	ACSR		115		1,297,085	278,729		1,575,814	4
1272	ACSR		230		15,316,916	9,176,302		24,493,218	5
1272	ACSR		230		3,526,147	1,315,880		4,842,027	6
1272	ACSR		230		8,759,580	7,966,211		16,725,791	7
795	ACSR		115		2,840,968			2,840,968	8
1272	ACSR		115		2,877,556	2,054,111		4,931,667	9
1272	ACSR		230		2,291,184	1,635,536		3,926,720	10
1272	ACSR		230		543,044	387,646		930,690	11
1272	ACSR		230		2,616,780	523,356		3,140,136	12
1272	ACSR		115		292,752	110,521		403,273	13
1272	ACSR		115		292,752	110,521		403,273	14
Various	ACSR		230		881,874	156,663		1,038,537	15
1272	ACSR		230		930,651	47,763		978,414	16
1272	ACSR		230		2,096,794	578,352		2,675,146	17
1272	ACSR		115		1,008,695	150,967		1,159,662	18
1272	ACSR		230		25,521,520	7,443,763		32,965,283	19
1272	ACSR		230		8,950,570	4,002,250		12,952,820	20
1272	ACSR		115		3,274,842			3,274,842	21
1272	ACSR		115		2,485,774			2,485,774	22
795	ACSR		115		886,081			886,081	23
1272	ACSR		230			7,443,763		7,443,763	24
795	ACSR		230						25
795	ACSR		115						26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					87,449,257	43,887,388		131,336,645	44

Schedule Page: 424 Line No.: 21 Column: k

Design Voltage 230kV

Schedule Page: 424 Line No.: 22 Column: k

Design Voltage 230kV

Schedule Page: 424 Line No.: 23 Column: k

Design Voltage 230kV

Schedule Page: 424 Line No.: 24 Column: d

On structures of another line (St. George #1).

Schedule Page: 424 Line No.: 25 Column: a

Negative numbers in column (c) represent retirements. Since the line was altered, this activity is being reported in accordance with Instruction No. 1 of this schedule.

Schedule Page: 424 Line No.: 26 Column: a

Negative numbers in column (c) represent retirements. Since the line was altered, this activity is being reported in accordance with Instruction No. 1 of this schedule.

Schedule Page: 424 Line No.: 26 Column: k

Design Voltage 230kV

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Aiken, Aiken County	Trans-U	115.00	46.00	
2	Aiken, Aiken County	Trans-U	115.00	12.00	
3	Barnwell, Barnwell County	Trans-U	115.00	46.00	
4	Batesburg, City of Batesburg	Trans-U	115.00	33.00	
5	Bayview, Mt. Pleasant City	Trans-U	115.00	23.00	
6	Blackville 115-46KV, Barnwell County	Trans-U	115.00	46.00	
7	Blackville 115-46KV, Barnwell County	Trans-U	115.00	12.00	
8	Burton Transmission, Beautfort County	Trans-U	230.00	115.00	
9	Burton Transmission, Beautfort County	Trans-U	115.00	46.00	
10	Cainhoy 230-115kV, Berkeley County	Trans-U	230.00	115.00	
11	Calhoun County, Calhoun County	Trans-U	115.00	46.00	
12	Calhoun Falls, Calhoun Falls City	Trans-U	115.00	46.00	
13	Calhoun Falls, Calhoun Falls City	Trans-U	46.00	12.00	
14	Canadys Sub, Colleton County	Trans-U	230.00	115.00	
15	Charleston, Charleston County	Trans-U	115.00	23.00	
16	Church Creek, Charleston County	Trans-U	230.00	115.00	
17	Coit Gas Turbine, Richland County	Trans-U	13.80	33.00	
18	Coit, Richland County	Trans-U	115.00	23.00	
19	Coit, Richland County	Trans-U	115.00	33.00	
20	Columbia Industrial Park, Richland County	Trans-U	230.00	115.00	
21	Cope, Orangeburg County	Trans-U	230.00	115.00	
22	Cope, Orangeburg County	Trans-U	115.00	230.00	
23	Denmark, City of Denmark	Trans-U	115.00	46.00	
24	Denny Terrace, Richland County	Trans-U	230.00	115.00	
25	Edenwood, City of Cayce	Trans-U	230.00	115.00	
26	Faber Place, City of North Charleston	Trans-U	115.00	23.00	
27	Faber Place, City of North Charleston	Trans-U	230.00	115.00	
28	Fairfax, Allendale County	Trans-U	115.00	46.00	
29	Fairfield Pumped Storage, Fairfield County	Trans-U	13.80	230.00	
30	Goose Creek, Hanahan City	Trans-U	230.00	115.00	
31	Graniteville #1, Aiken County	Trans-U	115.00	46.00	
32	Graniteville #1, Aiken County	Trans-U	230.00	115.00	
33	Graniteville #2, Aiken County	Trans-U	230.00	115.00	
34	Hagood Gas Turbine, Charleston County	Trans-U	13.80	115.00	
35	Hagood Gas Turbine, Charleston County	Trans-U	13.20	115.00	
36	Hagood Gas Turbine, Charleston County	Trans-U	13.80	4.16	
37	Hamlin, Charleston County	Trans-U	115.00	23.00	
38	Hampton, Hampton County	Trans-U	115.00	46.00	
39	Hanahan, Hanahan City	Trans-U	115.00	23.00	
40	Hanahan, Hanahan City	Trans-U	115.00	46.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hardeeville Gas Turbine, Jasper County	Trans-U	13.20	46.00	
2	Hardeeville, Jasper County	Trans-U	115.00	46.00	
3	Hobcaw, Charleston County	Trans-U	115.00	24.94	
4	Hopkins, Richland County	Trans-U	230.00	115.00	
5	Jasper 230kV, Jasper County	Trans-U	18.00	230.00	
6	Jasper 230kV, Jasper County	Trans-U	21.00	230.00	
7	Kendrick, Richland County	Trans-U	115.00	23.00	
8	Kendrick, Richland County	Trans-U	115.00	33.00	
9	Killian, Richland County	Trans-U	230.00	115.00	
10	Lake Murray, Lexington County	Trans-U	230.00	115.00	
11	Lyles, Richland County	Trans-U	230.00	115.00	
12	Lyles, Richland County	Trans-U	115.00	23.00	
13	Lyles, Richland County	Trans-U	115.00	35.00	
14	Lyles, Richland County	Trans-U	33.00	4.80	
15	McCormick, McCormick County	Trans-U	115.00	46.00	
16	McMeekin, Lexington County	Trans-U	13.20	115.00	
17	Orangeburg #1, Orangeburg County	Trans-U	115.00	46.00	
18	Orangeburg East 230KV, Orangeburg County	Trans-U	230.00	115.00	
19	Parr Gas Turbine, Fairfield County	Trans-U	13.20	115.00	
20	Parr Hydro, Fairfield County	Trans-U	2.30	13.80	
21	Parr Steam, Fairfield County	Trans-U	115.00	13.20	
22	Pepperhill, Charleston County	Trans-U	230.00	115.00	
23	Pineland, Richland County	Trans-U	230.00	115.00	
24	Rader, Richland County	Trans-U	115.00	23.00	
25	Ridgeville, City of Ridgeville	Trans-U	115.00	46.00	
26	Ritter, Colleton County	Trans-U	230.00	115.00	
27	Saluda Hydro, Lexington County	Trans-U	13.20	115.00	
28	Saluda Hydro, Lexington County	Trans-U	115.00	23.00	
29	Saluda Hydro, Lexington County	Trans-U	115.00	13.20	
30	Saluda River, Lexington County	Trans-U	230.00	115.00	
31	Santee, Orangeburg County	Trans-U	230.00	46.00	
32	Santee, Orangeburg County	Trans-U	115.00	46.00	
33	Santee, Orangeburg County	Trans-U	230.00	115.00	
34	Savannah River, Federal Property	Trans-U	230.00	115.00	
35	St. Andrews, Charleston City	Trans-U	115.00	23.00	
36	St. George, Dorchester County	Trans-U	115.00	46.00	
37	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	2.40	46.00	
38	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	46.00	2.40	
39	Stevens Creek Sub, Columbia Cnty Ga.	Trans-U	115.00	46.00	
40	Summerville, Berkeley County	Trans-U	230.00	115.00	

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Thomas Island, Charleston County	Trans-U	115.00	23.00	
2	Trenton, Edgefield County	Trans-U	115.00	23.00	
3	Trenton, Edgefield County	Trans-U	115.00	33.00	
4	Trenton, Edgefield County	Trans-U	115.00	46.00	
5	Urquhart 115KV, Aiken County	Trans-U	115.00	13.20	
6	Urquhart 115-46KV, Aiken County	Trans-U	115.00	46.00	
7	Urquhart 230KV, Aiken County	Trans-U	18.00	230.00	
8	Urquhart Gas Turbine, Aiken County	Trans-U	13.20	115.00	
9	V. C. Summer Substation, Fairfield County	Trans-U	22.00	230.00	
10	Ward, Saluda County	Trans-U	230.00	115.00	
11	Ward, Saluda County	Trans-U	115.00	23.00	
12	Ward, Saluda County	Trans-U	115.00	33.00	
13	Wateree Plant, Richland County	Trans-U	21.00	230.00	
14	Wateree Plant, Richland County	Trans-U	230.00	13.80	
15	Williams Gas Turbine, Berkeley County	Trans-U	13.20	115.00	
16	Williams St., Columbia City	Trans-U	115.00	33.00	
17	Williams St., Columbia City	Trans-U	115.00	23.00	
18	Williams Station, Berkeley County	Trans-U	20.00	230.00	
19	Williams Station, Berkeley County	Trans-U	115.00	230.00	
20	Williams Station, Berkeley County	Trans-U	230.00	4.16	
21	Williams Station, Berkeley County	Trans-U	230.00	23.00	
22	Williston Industrial Park , Barnwell County	Trans-U	115.00	46.00	
23	Yemassee, City of Yemassee	Trans-U	230.00	115.00	
24					
25	Distribution Substations:				
26	Adams Run, Charleston County	Dist-U	115.00	23.00	
27	Adams Run, Charleston County	Dist-U	115.00	46.00	
28	Aiken #2, Aiken County	Dist-U	115.00	12.00	
29	Aiken #3, Aiken County	Dist-U	115.00	12.00	
30	Aiken Hampton Avenue, Aiken City	Dist-U	115.00	12.00	
31	Aiken Industrial Park, Aiken City	Dist-U	46.00	23.00	
32	Aiken-Steifeltown, Aiken County	Dist-U	115.00	12.00	
33	Allendale, Allendale City	Dist-U	115.00	12.00	
34	Arrowwood Road, Richland County	Dist-U	115.00	23.00	
35	Ashley Phosphate, City of North Charleston	Dist-U	115.00	23.00	
36	Bacon's Bridge, Summerville City	Dist-U	115.00	23.00	
37	Baldock, Allendale County	Dist-U	115.00	12.00	
38	Bamberg Central, Bamberg City	Dist-U	43.80	12.00	
39	Barnwell City, Barnwell City	Dist-U	46.00	12.00	
40	Barnwell Heights, Barnwell City	Dist-U	46.00	12.00	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Barnwell Industrial Park, Barnwell County	Dist-U	43.80	12.00	
2	Batesburg City, Lexington County	Dist-U	33.00	8.00	
3	Bayfront, Charleston City	Dist-U	115.00	23.00	
4	Beaufort Central, Beaufort City	Dist-U	115.00	12.00	
5	Beaufort Industrial Park, Beaufort County	Dist-U	115.00	12.00	
6	Bee Street, Charleston County	Dist-U	115.00	14.40	
7	Beech Island, Aiken County	Dist-U	46.00	12.00	
8	Bellwright, Berkeley County	Dist-U	115.00	23.00	
9	Belmont, Richland County	Dist-U	115.00	23.00	
10	Belvedere, North Augusta City	Dist-U	115.00	12.00	
11	Blackville 46-12KV, Barnwell County	Dist-U	46.00	12.00	
12	Bluffton, Beaufort County	Dist-U	115.00	23.00	
13	Blythewood, Richland County	Dist-U	115.00	23.00	
14	Boney Rd. , Fairfield County	Dist-U	115.00	23.00	
15	Boney Rd. , Fairfield County	Dist-U	115.00	23.00	
16	Boone Hill, Dorchester County	Dist-U	115.00	23.00	
17	Bowman, Orangeburg County	Dist-U	115.00	8.00	
18	Brookwood, West Columbia City	Dist-U	115.00	23.00	
19	Burton Central, Beaufort County	Dist-U	115.00	12.00	
20	CAE Industrial Park, Lexington County	Dist-U	115.00	23.00	
21	Cainhoy, Berkeley County	Dist-U	115.00	23.00	
22	Calhoun Street, Columbia City	Dist-U	115.00	8.00	
23	Callawassie Island, Jasper County	Dist-U	115.00	23.00	
24	Carlisle, Carlisle City	Dist-U	115.00	23.00	
25	Carolina Bay, Charleston County	Dist-U	115.00	23.00	
26	Center Sub, Aiken County	Dist-U	46.00	23.00	23.00
27	Charleston Airport, N Charleston City	Dist-U	115.00	23.00	
28	Charlotte Street, Charleston City	Dist-U	115.00	14.40	
29	Church Creek, Charleston City	Dist-U	115.00	23.00	
30	Circle Drive, Richland County	Dist-U	115.00	8.00	
31	Clearwater, Aiken County	Dist-U	115.00	12.00	
32	Cloverleaf, Aiken County	Dist-U	115.00	12.00	
33	Colonial Heights, Richland County	Dist-U	115.00	23.00	
34	Columbia Airport, Springdale City	Dist-U	115.00	23.00	
35	Columbia Industrial Park, Richland County	Dist-U	115.00	23.00	
36	Congaree Creek, Cayce City	Dist-U	115.00	23.00	
37	Congaree Vista South, Richland County	Dist-U	115.00	23.00	
38	Coosaw, Charleston County	Dist-U	115.00	23.00	
39	Cromer Rd, Lexington County	Dist-U	115.00	23.00	
40	Deer Park, Charleston County	Dist-U	115.00	23.00	

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	 Secondary (d)	 Tertiary (e)
1	Denmark Industrial Park, Denmark City	Dist-U	46.00	12.00	
2	Dentsville, Richland County	Dist-U	115.00	23.00	
3	Dixiana, Lexington County	Dist-U	115.00	23.00	
4	East Columbia, Richland County	Dist-U	115.00	23.00	
5	Edmund, Lexington County	Dist-U	115.00	23.00	
6	Estill, Estill City	Dist-U	46.00	12.00	
7	Estill Southside, Estill City	Dist-U	46.00	12.00	
8	Eutawville, Orangeburg County	Dist-U	115.00	23.00	
9	Fairfax Central, Fairfax City	Dist-U	46.00	12.00	
10	Five Points, Columbia City	Dist-U	115.00	8.00	
11	Fort Johnston Road, Charleston County	Dist-U	115.00	23.00	
12	Frogmore, Beaufort County	Dist-U	115.00	23.00	
13	Gardens Corner, Beaufort County	Dist-U	115.00	23.00	
14	Gaston, Lexington County	Dist-U	115.00	23.00	
15	Gilbert, Lexington County	Dist-U	115.00	23.00	
16	Gills Creek, Richland County	Dist-U	115.00	23.00	
17	Grays Hill, Beaufort County	Dist-U	115.00	12.00	
18	Greengate, Richland County	Dist-U	115.00	23.00	
19	Grove Street, Charleston City	Dist-U	115.00	14.40	
20	Hampton City, Hampton County	Dist-U	46.00	12.00	
21	Hanahan Switching, Berkeley County	Dist-U	46.00	4.16	
22	Harbison, Lexington County	Dist-U	115.00	23.00	
23	Hardeeville, Hardeeville City	Dist-U	115.00	23.00	
24	Herrin, Allendale County	Dist-U	46.00	12.00	
25	Holly Hill, Holly Hill City	Dist-U	115.00	23.00	
26	Houndslake, Aiken County	Dist-U	115.00	12.00	
27	Howard Street, Richland County	Dist-U	33.00	8.00	
28	Irmo Town, Irmo City	Dist-U	115.00	23.00	
29	Isle of Palms, Isle of Palms City	Dist-U	115.00	23.00	
30	Jackson 46-12kV, Aiken County	Dist-U	46.00	12.00	
31	Jackson Street, Columbia City	Dist-U	115.00	8.00	
32	James Island, Charleston County	Dist-U	115.00	23.00	
33	James Prioleau, Charleston County	Dist-U	115.00	23.00	
34	Jasper Construction, Jasper County	Dist-U	115.00	23.00	
35	Johnston 115-23KV, Edgefield County	Dist-U	115.00	23.00	
36	Kilbourne Park, Richland County	Dist-U	115.00	23.00	
37	Killian, Richland County	Dist-U	115.00	23.00	
38	Kingswood, Richland County	Dist-U	115.00	23.00	
39	Ladies Island, Beaufort County	Dist-U	115.00	23.00	
40	Lake Carolina, Richland County	Dist-U	115.00	23.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lake Murray Training, Lexington County	Dist-U	115.00	23.00	
2	Langley, Aiken County	Dist-U	115.00	12.00	
3	Laurel Bay 115-12KV, Beaufort County	Dist-U	115.00	12.00	
4	Leesville 115-23KV, Lexington County	Dist-U	115.00	23.00	
5	Lexington 115-23kV, Lexington County	Dist-U	115.00	23.00	
6	Lexington East Side, Lexington County	Dist-U	115.00	23.00	
7	Lexington Industrial Park, Lexington County	Dist-U	115.00	23.00	
8	Lexington West Side, Lexington County	Dist-U	115.00	23.00	
9	Lower Richland, Richland County	Dist-U	115.00	23.00	
10	Maryville, Charleston County	Dist-U	115.00	23.00	
11	McCormick City 115-13KV, McCormick Cnty	Dist-U	115.00	12.00	
12	Meadowbrook, Beaufort County	Dist-U	115.00	23.00	
13	Meeting Street, Charleston County	Dist-U	115.00	14.40	
14	Middleburg Mall, Richland County	Dist-U	115.00	8.00	
15	Midway, Union County	Dist-U	115.00	13.80	
16	Midway, Union County	Dist-U	23.00	2.40	
17	Mt Pleasant, Charleston County	Dist-U	115.00	23.00	
18	Muller Avenue, Richland County	Dist-U	115.00	8.00	
19	Muller Avenue, Richland County	Dist-U	115.00	23.00	
20	Navy Yard 115-23kV, Federal Property, SC	Dist-U	115.00	23.00	
21	Navy Yard 115-23kV, Federal Property, SC	Dist-U	115.00	13.80	
22	Neeses, Orangeburg County	Dist-U	46.00	8.00	
23	Network, Richland County	Dist-U	115.00	13.80	
24	North 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
25	North Augusta, Aiken City	Dist-U	115.00	12.00	
26	North Bridge Terrace, Charleston County	Dist-U	115.00	23.00	
27	North Naval Weapons, Federal Property	Dist-U	115.00	13.80	
28	North Rhett, North Charleston City	Dist-U	115.00	23.00	
29	Northpointe Business Park, Charleston County	Dist-U	115.00	23.00	
30	Northwoods Mall, North Charleston City	Dist-U	230.00	23.00	
31	Okatie, Jasper County	Dist-U	115.00	23.00	
32	Old Fort, Dorchester County	Dist-U	115.00	23.00	
33	Osceola Park, Charleston County	Dist-U	115.00	23.00	
34	Palmetto Commerce Park, Charleston City	Dist-U	115.00	23.00	
35	Park Street, Columbia City	Dist-U	33.00	13.80	13.80
36	Parr 13.2-23KV, Fairfield County	Dist-U	23.00	13.80	
37	Parr Hill 115-23kV, Fairfield County	Dist-U	115.00	23.00	
38	Pelion, Lexington County	Dist-U	115.00	23.00	
39	Pendleton Street, Columbia City	Dist-U	115.00	8.00	
40	Pine Hill 230-23kV, Dorchester County	Dist-U	230.00	23.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Piney Woods Road, Richland County	Dist-U	115.00	23.00	
2	Platt Springs Rd., Lexington County	Dist-U	115.00	23.00	
3	Platt Springs Rd., Lexington County	Dist-U	115.00	23.00	
4	Pontiac, Richland County	Dist-U	230.00	23.00	
5	Port Park, Hanahan City	Dist-U	115.00	23.00	
6	Port Royal, Port Royal City	Dist-U	115.00	12.00	
7	Pritchardville, Beaufort County	Dist-U	115.00	23.00	
8	Quail Hollow, Lexington County	Dist-U	115.00	23.00	
9	Raborn Pointe, North Augusta City	Dist-U	115.00	12.00	
10	Rantowles, Charleston County	Dist-U	115.00	23.00	
11	Red House Rd, Charleston County	Dist-U	46.00	23.00	
12	Richland Mall, Forest Acres City	Dist-U	115.00	8.00	
13	Ridgeland, Jasper County	Dist-U	115.00	23.00	
14	Riverland Terrace, Charleston County	Dist-U	115.00	23.00	
15	Riverland Terrace, Charleston County	Dist-U	23.00	4.16	
16	Rosewood, Columbia City	Dist-U	33.00	8.00	
17	S. C. Research Association, Richland County	Dist-U	115.00	23.00	
18	Sage Mill Ind Park, Aiken County	Dist-U	115.00	12.00	
19	Saluda County, Saluda County	Dist-U	115.00	23.00	
20	Sandhill, Richland County	Dist-U	115.00	23.00	
21	Santee 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
22	Savage Road, Charleston County	Dist-U	115.00	23.00	
23	Saxe Gotha Industrial Park, Lexington County	Dist-U	115.00	23.00	
24	Seven Mile, North Charleston City	Dist-U	115.00	23.00	
25	Shell Point, Beaufort County	Dist-U	46.00	12.00	
26	Silver Bluff Rd, Aiken County	Dist-U	115.00	12.00	
27	S-Lubeca, Richland County	Dist-U	115.00	12.00	
28	South Main, Columbia City	Dist-U	115.00	8.00	
29	Sparkleberry, Richland County	Dist-U	115.00	23.00	23.00
30	Sparkleberry, Richland County	Dist-U	115.00	23.00	
31	Springdale, Lexington County	Dist-U	115.00	23.00	
32	St. George 115-12kV, Dorchester County	Dist-U	115.00	12.00	
33	St. Helena Island, Beaufort County	Dist-U	115.00	23.00	
34	St. Matthews 46-23kV, Calhoun County	Dist-U	46.00	23.00	23.00
35	Stono Park, Charleston City	Dist-U	115.00	23.00	
36	Summer Construction, Fairfield County	Dist-U	115.00	23.00	
37	Summerville Central, Berkeley County	Dist-U	115.00	23.00	
38	Summerville Industrial Park, Dorchester County	Dist-U	115.00	23.00	
39	Summerville Plaza, City of Summerville	Dist-U	115.00	23.00	
40	Summerville-Ladson, Charleston County	Dist-U	115.00	23.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Swansea, Lexington County	Dist-U	46.00	23.00	
2	Sweetwater, Aiken County	Dist-U	115.00	12.00	
3	Ten Mile, Charleston County	Dist-U	115.00	23.00	
4	Terminal, Richland County	Dist-U	33.00	8.00	
5	Timberlake, Lexington County	Dist-U	230.00	23.00	
6	Uptown, Columbia City	Dist-U	115.00	23.00	
7	Uptown, Columbia City	Dist-U	115.00	8.00	
8	Varnville, Varnville City	Dist-U	46.00	12.00	
9	Victory Gardens, Columbia City	Dist-U	115.00	8.00	
10	Wagener, Wagnener City	Dist-U	46.00	8.00	
11	Walterboro 115-23KV, Walterboro City	Dist-U	115.00	23.00	
12	Walterboro Forest Hill, Walterboro City	Dist-U	115.00	23.00	
13	Walterboro Ind Park, Walterboro City	Dist-U	115.00	23.00	
14	Walterboro South Side, Walterboro City	Dist-U	115.00	23.00	
15	West Columbia, West Columbia City	Dist-U	33.00	8.00	
16	White Gables, Dorchester County	Dist-U	115.00	23.00	
17	White Rock, Richland County	Dist-U	115.00	23.00	
18	Whitehall, Lexington County	Dist-U	115.00	23.00	
19	Williston, Williston City	Dist-U	115.00	12.00	
20	Winnsboro, Winnsboro City	Dist-U	115.00	23.00	
21	Woodfield Park, Richland County	Dist-U	115.00	23.00	
22	Yemassee Central, Yemassee City	Dist-U	115.00	23.00	
23					
24	Distribution Substations				
25	Under 10,000 KVA (36)	Dist-U			
26					
27	FUNCTIONAL SUMMARY OF CAPACITY				
28	Transmission Substations				
29	Distribution Substations				
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
22	1					2
56	2					3
28	1	1				4
75	2	1				5
28	1					6
28	1					7
224	1					8
112	2	4				9
336	1					10
28	1					11
50	2	2				12
7	1					13
224	1	1				14
67	2					15
896	3					16
56	2					17
22	1					18
56	1					19
336	1					20
224	1					21
549	1					22
56	2					23
672	2					24
448	2					25
73	3					26
672	2	1				27
56	2					28
717	4	1				29
336	1					30
56	2					31
448	2					32
336	1					33
60	1					34
147	1					35
6	1					36
112	3	1				37
84	3	2				38
78	3					39
56	2					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1					1
28	1					2
28	1					3
336	1					4
700	3					5
500	1					6
56	2	1				7
56	1					8
336	1					9
672	2	1				10
336	1	1				11
56	2					12
56	1					13
8	3					14
58	2	1				15
350	2					16
81	3					17
672	2					18
98	2	1				19
25	3					20
34	1					21
336	1					22
672	2	1				23
45	2					24
28	1					25
336	1					26
133	3					27
65	2					28
133	2					29
336	1					30
28	1					31
28	1					32
140	1					33
672	2					34
22	1					35
28	1					36
14	2					37
14	2					38
28	1	1				39
672	2					40

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
75	2					1
22	1					2
23	3	1				3
56	2					4
325	6	2				5
48	2					6
467	1	1				7
176	3	1				8
1232	1	1				9
364	2	1				10
22	1					11
28	1					12
1008	2	1				13
75	2					14
70	1					15
106	4	1				16
60	2					17
785	1	1				18
560	2					19
93	2					20
101	2					21
32	6					22
784	3					23
						24
						25
50	2					26
112	2					27
50	2					28
50	2					29
28	1					30
11	1					31
22	1					32
22	1					33
22	1					34
60	2					35
37	1					36
22	1					37
14	2					38
11	1					39
11	1					40

SUBSTATIONS (Continued)

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11	1					1
11	1					2
40	1					3
28	1					4
22	1					5
202	4					6
11	1					7
28	1					8
50	2					9
50	2					10
11	1					11
56	2					12
75	2					13
23	1					14
22	1					15
60	2					16
11	1					17
28	1					18
56	2					19
28	1					20
56	2					21
22	1					22
28	1	1				23
20	4					24
28	1					25
11	1					26
40	1					27
101	4					28
75	2					29
22	1					30
28	1					31
22	1					32
22	1					33
22	1					34
40	1					35
28	1					36
37	1					37
37	1					38
37	1					39
45	2					40

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

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11	1	1				1
45	2					2
65	2					3
28	1					4
22	1					5
14	1					6
25	2	1				7
50	2					8
18	2					9
22	1					10
50	2					11
28	1					12
22	1					13
50	2					14
22	1					15
37	1					16
22	1					17
37	1					18
22	1					19
21	2					20
14	2	1				21
50	2					22
28	1	1				23
11	1					24
50	4	1				25
28	1					26
11	1					27
56	2					28
50	2					29
11	1					30
22	1					31
45	2					32
28	1					33
11	1					34
22	1					35
60	2					36
37	1					37
50	2					38
50	2					39
65	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
22	1					2
28	1					3
28	1					4
65	2	1				5
37	1					6
60	2	1				7
75	2					8
60	2					9
37	1					10
11	1	1				11
22	1					12
22	1					13
22	1					14
20	1	2				15
1	3					16
77	2					17
22	1					18
28	1					19
28	1					20
22	1					21
11	1					22
67	3					23
11	1					24
28	1					25
45	2					26
22	1					27
28	1					28
37	1					29
75	2	1				30
28	1					31
60	2					32
75	2					33
65	2					34
44	2	1				35
22	1					36
22	1					37
22	1	1				38
45	2					39
37	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
28	1					2
22	1					3
75	2					4
22	1					5
28	1					6
37	1					7
37	1	2				8
22	1					9
28	1					10
45	2	1				11
45	2					12
22	1	1				13
22	1					14
4	1					15
21	2					16
22	1					17
28	1					18
22	1					19
75	2					20
21	2					21
45	2					22
37	1					23
22	1					24
25	2	1				25
22	1					26
22	1					27
22	1					28
38	1					29
37	1					30
45	2	1				31
28	1					32
50	2					33
23	2	1				34
37	1					35
22	1					36
40	1					37
50	2					38
37	1					39
60	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1	1				1
28	1	1				2
22	1					3
11	1					4
37	1	1				5
37	1	1				6
23	1					7
11	1					8
22	1					9
11	1					10
22	1					11
40	1					12
28	1					13
22	1					14
18	2					15
37	1					16
50	2	1				17
22	1					18
22	1					19
45	2					20
45	2					21
22	1					22
						23
6725						24
204						25
						26
						27
22607						28
6929						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.7 Line No.: 25 Column: c

Various

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Natural Gas Commodity and Demand	SCANA Energy Marketing, Inc.	803/547	127,428,365
3	Refined Coal Purchases	Canadys Refined Coal, LLC.	419	73,191,939
4				
5				
6				
7				
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10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Rental Fee for Use of Assets	SCANA Services, Inc.	454/493	4,873,572
22	Coal Sales	Canadys Refined Coal, LLC	419	72,741,710
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
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41				
42				

Schedule Page: 429 Line No.: 3 Column: b

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and selling of refined coal to reduce emissions.

Schedule Page: 429 Line No.: 8 Column: a

The transactions below represent activities billed by SCANA Services, Inc. to SCE&G during the reporting period.

REPORTING BUSINESS UNIT	Category	FERC Account	Direct Billed	Allocated	Total Billed
SCEG	Corporate Security	1070	$602,544	$41,881	$644,425
SCEG	Corporate Security	1180	$6,544	$5,727	$12,271
SCEG	Corporate Security	1823	$78,460	$0	$78,460
SCEG	Corporate Security	1860	$0	$3,213	$3,213
SCEG	Corporate Security	4081	$160,358	$45,198	$205,556
SCEG	Corporate Security	4210	$0	$3,607	$3,607
SCEG	Corporate Security	4265	$64,252	$21,806	$86,058
SCEG	Corporate Security	9030	$5	$0	$5
SCEG	Corporate Security	9040	($704)	$0	($704)
SCEG	Corporate Security	9050	$106	$0	$106
SCEG	Corporate Security	9200	$2,268,582	$639,961	$2,908,543
SCEG	Corporate Security	9210	$316,034	$66,611	$382,645
SCEG	Corporate Security	9230	$3,337,637	$884,551	$4,222,188
SCEG	Corporate Security	9260	$576,829	$326,694	$903,523
SCEG	Corporate Security	9280	$2,502	$0	$2,502
SCEG	Corporate Security	9310	$63,421	$460	$63,881
SCEG	Corporate Security	9350	$12,195	$6,904	$19,099
SCEG	Customer Services & Operational Support	1070	$1,503,601	$221,986	$1,725,588
SCEG	Customer Services & Operational Support	1180	$539,287	$30,355	$569,642
SCEG	Customer Services & Operational Support	1823	$422,050	$0	$422,050
SCEG	Customer Services & Operational Support	1840	$322,639	$6	$322,646
SCEG	Customer Services & Operational Support	1860	$13,400	$17,030	$30,430
SCEG	Customer Services & Operational Support	4081	$898,323	$122,540	$1,020,863
SCEG	Customer Services & Operational Support	4082	$656	$2,140	$2,796
SCEG	Customer Services & Operational Support	4160	$78,905	$24,654	$103,559
SCEG	Customer Services & Operational Support	4171	$8,652	$7,940	$16,592
SCEG	Customer Services & Operational Support	4210	$0	$19,116	$19,116
SCEG	Customer Services & Operational Support	4261	$209	$2,955	$3,164
SCEG	Customer Services & Operational Support	4265	$60,189	$8,696	$68,886
SCEG	Customer Services & Operational Support	5370	$172	$0	$172
SCEG	Customer Services & Operational Support	5617	$1,515	$0	$1,515
SCEG	Customer Services & Operational Support	5800	$80,807	$0	$80,807
SCEG	Customer Services & Operational Support	5880	$475,320	$0	$475,320
SCEG	Customer Services & Operational Support	5930	$177,290	$0	$177,290
SCEG	Customer Services & Operational Support	8740	$129,623	$978	$130,601
SCEG	Customer Services & Operational Support	8800	$0	$0	$0
SCEG	Customer Services & Operational Support	8850	$1,955	$0	$1,955

SCEG	Customer Services & Operational Support	9010	$574,581	$7,396	$581,978
SCEG	Customer Services & Operational Support	9020	$33,566	$0	$33,566
SCEG	Customer Services & Operational Support	9030	$14,424,258	$1,758,417	$16,182,675
SCEG	Customer Services & Operational Support	9050	$2,378,122	($22,326)	$2,355,796
SCEG	Customer Services & Operational Support	9080	$52,897	$0	$52,897
SCEG	Customer Services & Operational Support	9130	$37	$0	$37
SCEG	Customer Services & Operational Support	9160	$67	$0	$67
SCEG	Customer Services & Operational Support	9200	$1,030,927	$186,080	$1,217,007
SCEG	Customer Services & Operational Support	9210	$630,728	$46,069	$676,797
SCEG	Customer Services & Operational Support	9230	$318,553	$0	$318,553
SCEG	Customer Services & Operational Support	9260	$3,210,313	$1,321,341	$4,531,654
SCEG	Customer Services & Operational Support	9301	$28,000	$0	$28,000
SCEG	Customer Services & Operational Support	9302	$1,573	$0	$1,573
SCEG	Customer Services & Operational Support	9310	$3,485	$43,476	$46,961
SCEG	Customer Services & Operational Support	9350	$132,637	$2,500	$135,138
SCEG	Employee Services	1070	$1,319,021	$975,876	$2,294,898
SCEG	Employee Services	1080	$3,178	$0	$3,178
SCEG	Employee Services	1180	$96,179	$179,360	$275,538
SCEG	Employee Services	1190	$8,651	$0	$8,651
SCEG	Employee Services	1540	$9,163	$0	$9,163
SCEG	Employee Services	1630	$3,997	$0	$3,997
SCEG	Employee Services	1823	$34,842	$0	$34,842
SCEG	Employee Services	1840	$534,710	$671,900	$1,206,610
SCEG	Employee Services	1860	($26,209)	$7,596	($18,613)
SCEG	Employee Services	4081	($223,684)	$294,577	$70,893
SCEG	Employee Services	4082	$672	$3,108	$3,779
SCEG	Employee Services	4160	$12,143	$6,029	$18,172
SCEG	Employee Services	4171	$6,923	$7,669	$14,592
SCEG	Employee Services	4210	$0	$8,527	$8,527
SCEG	Employee Services	4264	$3,770	$0	$3,770
SCEG	Employee Services	4265	$49,384	$1,048,684	$1,098,068
SCEG	Employee Services	5000	$276	$0	$276
SCEG	Employee Services	5020	$10	$0	$10
SCEG	Employee Services	5060	$3,378	$0	$3,378
SCEG	Employee Services	5120	$150	$0	$150
SCEG	Employee Services	5130	$23	$0	$23
SCEG	Employee Services	5140	$175	$0	$175
SCEG	Employee Services	5170	$96	$0	$96
SCEG	Employee Services	5240	$114,338	$0	$114,338
SCEG	Employee Services	5300	$50	$0	$50
SCEG	Employee Services	5320	$432	$0	$432
SCEG	Employee Services	5350	$404	$0	$404
SCEG	Employee Services	5370	$3,158	$0	$3,158
SCEG	Employee Services	5380	$808	$0	$808
SCEG	Employee Services	5390	$91	$0	$91
SCEG	Employee Services	5490	$114	$0	$114

SCEG	Employee Services	5530	$340	$0	$340
SCEG	Employee Services	5600	$10,365	$0	$10,365
SCEG	Employee Services	5617	$243	$0	$243
SCEG	Employee Services	5620	$826	$0	$826
SCEG	Employee Services	5660	$1,495	$0	$1,495
SCEG	Employee Services	5700	$296	$0	$296
SCEG	Employee Services	5710	$472	$0	$472
SCEG	Employee Services	5830	$1,822	$0	$1,822
SCEG	Employee Services	5840	$13	$0	$13
SCEG	Employee Services	5850	$285	$0	$285
SCEG	Employee Services	5880	$41,942	$0	$41,942
SCEG	Employee Services	5920	$1,951	$0	$1,951
SCEG	Employee Services	5930	$460	$0	$460
SCEG	Employee Services	5970	$621	$0	$621
SCEG	Employee Services	8410	$9	$0	$9
SCEG	Employee Services	8700	$84,119	$626	$84,745
SCEG	Employee Services	8740	$73,961	$54,838	$128,799
SCEG	Employee Services	8780	$100	$0	$100
SCEG	Employee Services	8800	$12,441	$25	$12,466
SCEG	Employee Services	8870	$126,038	$0	$126,038
SCEG	Employee Services	9020	$0	$159	$159
SCEG	Employee Services	9030	$488,333	$208,322	$696,655
SCEG	Employee Services	9050	$90,347	$0	$90,347
SCEG	Employee Services	9080	$9,904	$0	$9,904
SCEG	Employee Services	9120	$2,716	$0	$2,716
SCEG	Employee Services	9200	($433,434)	$3,129,024	$2,695,590
SCEG	Employee Services	9210	$188,294	$534,664	$722,958
SCEG	Employee Services	9230	$0	$608,202	$608,202
SCEG	Employee Services	9250	$1,432,978	$262,807	$1,695,784
SCEG	Employee Services	9260	$667,580	$1,266,961	$1,934,541
SCEG	Employee Services	9302	$483	$62,922	$63,405
SCEG	Employee Services	9310	$22,230	$1,285,382	$1,307,612
SCEG	Employee Services	9350	$9,531	$10,099	$19,630
SCEG	Environmental Services	1070	$121,231	$33,596	$154,827
SCEG	Environmental Services	1080	$220,075	$0	$220,075
SCEG	Environmental Services	1180	$56,095	$4,594	$60,689
SCEG	Environmental Services	1190	$1,121	$0	$1,121
SCEG	Environmental Services	1210	$967	$0	$967
SCEG	Environmental Services	1840	$95,154	$0	$95,154
SCEG	Environmental Services	1860	$71,423	$2,578	$74,001
SCEG	Environmental Services	4081	$124,045	$24,629	$148,674
SCEG	Environmental Services	4082	$2,580	$0	$2,580
SCEG	Environmental Services	4171	$10,025	$0	$10,025
SCEG	Environmental Services	4210	$0	$2,893	$2,893
SCEG	Environmental Services	4261	$4,848	$358	$5,205
SCEG	Environmental Services	4265	$21,017	$33,453	$54,470

SCEG	Environmental Services	5060	$4,634	$0	$4,634
SCEG	Environmental Services	5240	$2,317	$0	$2,317
SCEG	Environmental Services	5390	$4,634	$0	$4,634
SCEG	Environmental Services	5490	$772	$0	$772
SCEG	Environmental Services	5660	$37,841	$0	$37,841
SCEG	Environmental Services	5880	$22,395	$0	$22,395
SCEG	Environmental Services	5920	$9,637	$0	$9,637
SCEG	Environmental Services	7350	$1,008,830	$0	$1,008,830
SCEG	Environmental Services	9200	$1,386,188	$345,402	$1,731,590
SCEG	Environmental Services	9210	$219,431	$86,227	$305,658
SCEG	Environmental Services	9230	$750,537	$193,406	$943,943
SCEG	Environmental Services	9260	$453,886	$222,126	$676,012
SCEG	Environmental Services	9302	$57,457	$0	$57,457
SCEG	Environmental Services	9310	$3,073	$0	$3,073
SCEG	Environmental Services	9320	$490	$0	$490
SCEG	Environmental Services	9350	$239,422	$0	$239,422
SCEG	Executive Services	1070	$2,086,792	$54,456	$2,141,249
SCEG	Executive Services	1180	$0	$7,447	$7,447
SCEG	Executive Services	1840	$208,193	$0	$208,193
SCEG	Executive Services	1860	$0	$4,178	$4,178
SCEG	Executive Services	4081	$73,971	$86,821	$160,792
SCEG	Executive Services	4082	$1,502	$18,278	$19,780
SCEG	Executive Services	4171	$5,297	$68,123	$73,420
SCEG	Executive Services	4210	$0	$4,690	$4,690
SCEG	Executive Services	4261	$3,000	$0	$3,000
SCEG	Executive Services	4264	$119,710	$0	$119,710
SCEG	Executive Services	4265	$90,186	$617,972	$708,158
SCEG	Executive Services	5170	$79,529	$0	$79,529
SCEG	Executive Services	5240	$5,016	$0	$5,016
SCEG	Executive Services	5660	$74,422	$0	$74,422
SCEG	Executive Services	5880	$28,539	$0	$28,539
SCEG	Executive Services	5930	($6,606)	$0	($6,606)
SCEG	Executive Services	9200	$792,127	$1,267,748	$2,059,876
SCEG	Executive Services	9210	$21,886	$41,204	$63,090
SCEG	Executive Services	9260	$241,458	$486,804	$728,262
SCEG	Executive Services	9280	$18,866	$0	$18,866
SCEG	Executive Services	9302	$981,236	$0	$981,236
SCEG	Executive Services	9310	$0	$6,115	$6,115
SCEG	Executive Services	9350	$5,513	$419	$5,932
SCEG	Financial Services	1070	$12,219,395	$285,143	$12,504,538
SCEG	Financial Services	1080	$0	$0	$0
SCEG	Financial Services	1180	$6,522,713	$45,144	$6,567,857
SCEG	Financial Services	1823	$680,890	$0	$680,890
SCEG	Financial Services	1840	$87,418	$116,872	$204,290
SCEG	Financial Services	1860	$46,016	$9,245	$55,260
SCEG	Financial Services	4081	$230,600	$4,947,612	$5,178,212

SCEG	Financial Services	4082	$152,625	$6,554	$159,179
SCEG	Financial Services	4111		$144,500	$144,500
SCEG	Financial Services	4112		$2,600	$2,600
SCEG	Financial Services	4140	$0	$12,404,628	$12,404,628
SCEG	Financial Services	4160	$14,075	$19,485	$33,560
SCEG	Financial Services	4171	$3,906	$707	$4,612
SCEG	Financial Services	4210	$0	$10,377	$10,377
SCEG	Financial Services	4261	$151	$0	$151
SCEG	Financial Services	4263	$351	$0	$351
SCEG	Financial Services	4264	($1,371)	$4,074	$2,703
SCEG	Financial Services	4265	$77,870	$324,304	$402,174
SCEG	Financial Services	4300	$0	$6,588,411	$6,588,411
SCEG	Financial Services	4320	$0	($14,251)	($14,251)
SCEG	Financial Services	5240	($22,260)	$0	($22,260)
SCEG	Financial Services	5320	$3,557	$0	$3,557
SCEG	Financial Services	5370	$1,619	$0	$1,619
SCEG	Financial Services	5560	$93,025	$0	$93,025
SCEG	Financial Services	5880	$5,399	$0	$5,399
SCEG	Financial Services	5920	($9,637)	$0	($9,637)
SCEG	Financial Services	7350	($656,834)	$0	($656,834)
SCEG	Financial Services	9030	$462,770	$66,155	$528,925
SCEG	Financial Services	9050	$7,071	$0	$7,071
SCEG	Financial Services	9080	$5,079	$0	$5,079
SCEG	Financial Services	9200	$2,799,016	$3,413,402	$6,212,418
SCEG	Financial Services	9210	$91,211	($63,569)	$27,641
SCEG	Financial Services	9230	$3,005,185	$2,385,165	$5,390,350
SCEG	Financial Services	9240	($443,233)	$411,449	($31,784)
SCEG	Financial Services	9250	$1,732,259	($4,479)	$1,727,780
SCEG	Financial Services	9260	$969,791	$1,529,430	$2,499,221
SCEG	Financial Services	9280	$5,208	$0	$5,208
SCEG	Financial Services	9302	$0	$269,043	$269,043
SCEG	Financial Services	9310	$9,670	$12,575	$22,245
SCEG	Financial Services	9350	$476,270	$221,949	$698,219
SCEG	Gas Control Coordination & Gas Engineering Services	1070	$0	$24,368	$24,368
SCEG	Gas Control Coordination & Gas Engineering Services	1180	$593,571	$3,332	$596,903
SCEG	Gas Control Coordination & Gas Engineering Services	1190	$822	$0	$822
SCEG	Gas Control Coordination & Gas Engineering Services	1823	$3,471,102	$0	$3,471,102
SCEG	Gas Control Coordination & Gas Engineering Services	1860	$48,155	$1,870	$50,025
SCEG	Gas Control Coordination & Gas Engineering Services	4081	$57,773	$45,209	$102,982
SCEG	Gas Control Coordination & Gas Engineering Services	4210	$0	$2,099	$2,099
SCEG	Gas Control Coordination & Gas Engineering Services	4265	$1,005	$145	$1,151
SCEG	Gas Control Coordination & Gas Engineering Services	5530	$599	$0	$599
SCEG	Gas Control Coordination & Gas Engineering Services	8400	$61,298	$2,001	$63,299
SCEG	Gas Control Coordination & Gas Engineering Services	8410	($24,846)	$2,341	($22,506)
SCEG	Gas Control Coordination & Gas Engineering Services	8610	$0	$756	$756
SCEG	Gas Control Coordination & Gas Engineering Services	8670	$0	$227	$227

SCEG	Gas Control Coordination & Gas Engineering Services	8700	$365,462	$252,924	$618,386
SCEG	Gas Control Coordination & Gas Engineering Services	8740	$165,396	$349,928	$515,325
SCEG	Gas Control Coordination & Gas Engineering Services	8800	$2,015	$951	$2,967
SCEG	Gas Control Coordination & Gas Engineering Services	8850	$3,792	$95	$3,887
SCEG	Gas Control Coordination & Gas Engineering Services	8870	$376,636	$5,841	$382,478
SCEG	Gas Control Coordination & Gas Engineering Services	9100	$175,750	$300	$176,050
SCEG	Gas Control Coordination & Gas Engineering Services	9120	$0	$486	$486
SCEG	Gas Control Coordination & Gas Engineering Services	9200	$370,311	$92,718	$463,030
SCEG	Gas Control Coordination & Gas Engineering Services	9210	$11,130	$34,213	$45,343
SCEG	Gas Control Coordination & Gas Engineering Services	9260	$216,042	$263,012	$479,054
SCEG	Gas Control Coordination & Gas Engineering Services	9302	$141,969	$0	$141,969
SCEG	Gas Control Coordination & Gas Engineering Services	9350	$0	$10,798	$10,798
SCEG	Gas Measurement Services	1070	$0	$5,656	$5,656
SCEG	Gas Measurement Services	1180	$403,161	$773	$403,935
SCEG	Gas Measurement Services	1630	$80,745	$0	$80,745
SCEG	Gas Measurement Services	1860	$0	$434	$434
SCEG	Gas Measurement Services	4081	$8,594	$4,499	$13,093
SCEG	Gas Measurement Services	4210	$0	$487	$487
SCEG	Gas Measurement Services	8700	$49,739	$10,033	$59,771
SCEG	Gas Measurement Services	8740	$0	$211	$211
SCEG	Gas Measurement Services	8800	$10,128	$1,825	$11,953
SCEG	Gas Measurement Services	8900	$218	$0	$218
SCEG	Gas Measurement Services	8930	$68,940	$35,276	$104,216
SCEG	Gas Measurement Services	9200	$1,386	$57,028	$58,415
SCEG	Gas Measurement Services	9210	($7,184)	$9,672	$2,488
SCEG	Gas Measurement Services	9230	$0	$2,297	$2,297
SCEG	Gas Measurement Services	9260	$30,358	$39,054	$69,412
SCEG	Gas Measurement Services	9310	$0	$270,182	$270,182
SCEG	Gas Supply and Fuel Procurement	1070	$437	$10,253	$10,691
SCEG	Gas Supply and Fuel Procurement	1180	$0	$1,402	$1,402
SCEG	Gas Supply and Fuel Procurement	1860	$0	$787	$787
SCEG	Gas Supply and Fuel Procurement	4081	$24,447	$26,412	$50,859
SCEG	Gas Supply and Fuel Procurement	4210	$0	$883	$883
SCEG	Gas Supply and Fuel Procurement	4265	$0	$7,313	$7,313
SCEG	Gas Supply and Fuel Procurement	5240	$41	$0	$41
SCEG	Gas Supply and Fuel Procurement	8030	$0	$0	$0
SCEG	Gas Supply and Fuel Procurement	9200	$354,781	$380,260	$735,041
SCEG	Gas Supply and Fuel Procurement	9210	$5,260	$127,205	$132,465
SCEG	Gas Supply and Fuel Procurement	9260	$91,909	$136,860	$228,769
SCEG	Information Services	1070	$13,457,791	$782,064	$14,239,855
SCEG	Information Services	1080	$44,356	$0	$44,356
SCEG	Information Services	1180	$502,620	$115,412	$618,032
SCEG	Information Services	1210	$1,225,508	$0	$1,225,508
SCEG	Information Services	1630	$196,864	$0	$196,864
SCEG	Information Services	1822	$3,104	$0	$3,104
SCEG	Information Services	1823	$4,290,551	$0	$4,290,551

SCEG	Information Services	1840	$917,649	$469,597	$1,387,246
SCEG	Information Services	1860	$328,828	$1,006	$329,834
SCEG	Information Services	2270	($1,231,124)	$0	($1,231,124)
SCEG	Information Services	2430	$5,617	$0	$5,617
SCEG	Information Services	4081	$25,226	$2,167	$27,393
SCEG	Information Services	4082	$3,739	$0	$3,739
SCEG	Information Services	4140	$0	$118,445	$118,445
SCEG	Information Services	4160	$42,405	$37,646	$80,051
SCEG	Information Services	4171	$132,492	$0	$132,492
SCEG	Information Services	4210	$0	$1,129	$1,129
SCEG	Information Services	4261	$0	$10,818	$10,818
SCEG	Information Services	4264	$0	$4,412	$4,412
SCEG	Information Services	4265	$2,690,078	$151,053	$2,841,131
SCEG	Information Services	5000	$9,759	$0	$9,759
SCEG	Information Services	5010	$13,146	$0	$13,146
SCEG	Information Services	5060	$1,139,807	$0	$1,139,807
SCEG	Information Services	5170	$11,388	$0	$11,388
SCEG	Information Services	5190	$106,100	$0	$106,100
SCEG	Information Services	5200	$351,724	$0	$351,724
SCEG	Information Services	5240	$6,425,742	$0	$6,425,742
SCEG	Information Services	5290	$44,083	$0	$44,083
SCEG	Information Services	5300	$126	$0	$126
SCEG	Information Services	5310	$0	$0	$0
SCEG	Information Services	5320	$1,743,641	$0	$1,743,641
SCEG	Information Services	5350	$2,749	$0	$2,749
SCEG	Information Services	5370	$9,422	$0	$9,422
SCEG	Information Services	5380	$840	$0	$840
SCEG	Information Services	5390	$155,078	$0	$155,078
SCEG	Information Services	5440	$467	$0	$467
SCEG	Information Services	5460	$4,519	$0	$4,519
SCEG	Information Services	5490	$117,453	$0	$117,453
SCEG	Information Services	5560	$184,277	$0	$184,277
SCEG	Information Services	5600	$6,453	$0	$6,453
SCEG	Information Services	5611	$6,988	$0	$6,988
SCEG	Information Services	5612	$43,875	$0	$43,875
SCEG	Information Services	5620	$2,684,039	$0	$2,684,039
SCEG	Information Services	5630	$873	$0	$873
SCEG	Information Services	5660	$186,406	$0	$186,406
SCEG	Information Services	5680	$43,216	$0	$43,216
SCEG	Information Services	5700	$274,814	$0	$274,814
SCEG	Information Services	5710	$1,616	$0	$1,616
SCEG	Information Services	5730	$164,152	$0	$164,152
SCEG	Information Services	5800	$2,066	$0	$2,066
SCEG	Information Services	5810	$1,417	$0	$1,417
SCEG	Information Services	5820	$174,577	$0	$174,577
SCEG	Information Services	5830	$5,809	$0	$5,809

SCEG	Information Services	5860	$33,499	$0	$33,499
SCEG	Information Services	5880	$2,925,689	$0	$2,925,689
SCEG	Information Services	5920	$57,011	$0	$57,011
SCEG	Information Services	5930	$107,792	$0	$107,792
SCEG	Information Services	5940	$58,110	$0	$58,110
SCEG	Information Services	5960	$19,058	$0	$19,058
SCEG	Information Services	5970	$100,320	$0	$100,320
SCEG	Information Services	5980	$865	$0	$865
SCEG	Information Services	8410	$12,594	$0	$12,594
SCEG	Information Services	8439	$2,561	$0	$2,561
SCEG	Information Services	8700	$4,860	$0	$4,860
SCEG	Information Services	8710	$8,457	$0	$8,457
SCEG	Information Services	8740	$95,705	$34,473	$130,178
SCEG	Information Services	8750	$6,898	$0	$6,898
SCEG	Information Services	8760	$414,580	$0	$414,580
SCEG	Information Services	8780	$5,730	$0	$5,730
SCEG	Information Services	8790	$238	$0	$238
SCEG	Information Services	8800	$438,450	$0	$438,450
SCEG	Information Services	8850	$0	$4,093	$4,093
SCEG	Information Services	8870	$491	$0	$491
SCEG	Information Services	8920	$386,680	$0	$386,680
SCEG	Information Services	8930	$65,745	$0	$65,745
SCEG	Information Services	8940	$429	$0	$429
SCEG	Information Services	9010	$33,723	$0	$33,723
SCEG	Information Services	9020	$589,678	$159,426	$749,104
SCEG	Information Services	9030	$14,637,250	$277,624	$14,914,874
SCEG	Information Services	9050	$609,081	$0	$609,081
SCEG	Information Services	9070	$824	$0	$824
SCEG	Information Services	9080	$153,700	$0	$153,700
SCEG	Information Services	9100	$272	$0	$272
SCEG	Information Services	9110	$107	$0	$107
SCEG	Information Services	9120	$300,771	$0	$300,771
SCEG	Information Services	9160	$241	$513,655	$513,896
SCEG	Information Services	9200	($186,759)	$26,473	($160,286)
SCEG	Information Services	9210	$6,709,766	$4,798,457	$11,508,223
SCEG	Information Services	9230	$316	$11	$327
SCEG	Information Services	9260	$91,537	$58,680	$150,217
SCEG	Information Services	9302	$304,143	$3,865	$308,009
SCEG	Information Services	9310	$642,447	$51,462	$693,909
SCEG	Information Services	9350	$1,341,100	$3,097	$1,344,197
SCEG	Land & Facilities Management	1070	$3,692,365	$49,241	$3,741,607
SCEG	Land & Facilities Management	1080	$1,961,645	$0	$1,961,645
SCEG	Land & Facilities Management	1180	$3,677,174	$8,201	$3,685,375
SCEG	Land & Facilities Management	1190	$49,203	$0	$49,203
SCEG	Land & Facilities Management	1210	$997,778	$0	$997,778
SCEG	Land & Facilities Management	1630	$18,085	$0	$18,085

SCEG	Land & Facilities Management	1823	$330	$0	$330
SCEG	Land & Facilities Management	1840	$129,661	$21,476	$151,138
SCEG	Land & Facilities Management	1860	$149,673	$1,628	$151,300
SCEG	Land & Facilities Management	4081	$59,221	$48,739	$107,960
SCEG	Land & Facilities Management	4082	$13,308	$5,291	$18,599
SCEG	Land & Facilities Management	4160	$0	$142,331	$142,331
SCEG	Land & Facilities Management	4171	$40,528	$19,634	$60,162
SCEG	Land & Facilities Management	4210	$0	$1,827	$1,827
SCEG	Land & Facilities Management	4265	$351,049	$105,128	$456,177
SCEG	Land & Facilities Management	5010	$731,922	$0	$731,922
SCEG	Land & Facilities Management	5060	$45,395	$0	$45,395
SCEG	Land & Facilities Management	5110	$79,438	$0	$79,438
SCEG	Land & Facilities Management	5120	$53,281	$0	$53,281
SCEG	Land & Facilities Management	5140	$18,766	$0	$18,766
SCEG	Land & Facilities Management	5170	$25,046	$0	$25,046
SCEG	Land & Facilities Management	5240	$79,260	$0	$79,260
SCEG	Land & Facilities Management	5290	$589,644	$0	$589,644
SCEG	Land & Facilities Management	5300	$1,100	$0	$1,100
SCEG	Land & Facilities Management	5310	$0	$0	$0
SCEG	Land & Facilities Management	5320	$31,098	$0	$31,098
SCEG	Land & Facilities Management	5370	$6,295	$0	$6,295
SCEG	Land & Facilities Management	5390	$26,990	$0	$26,990
SCEG	Land & Facilities Management	5430	$108,998	$0	$108,998
SCEG	Land & Facilities Management	5440	$6,805	$0	$6,805
SCEG	Land & Facilities Management	5450	$0	$0	$0
SCEG	Land & Facilities Management	5460	$6,502	$0	$6,502
SCEG	Land & Facilities Management	5480	$1,554	$0	$1,554
SCEG	Land & Facilities Management	5490	$29,394	$0	$29,394
SCEG	Land & Facilities Management	5510	$275	$0	$275
SCEG	Land & Facilities Management	5520	$18,130	$0	$18,130
SCEG	Land & Facilities Management	5530	$18,495	$0	$18,495
SCEG	Land & Facilities Management	5540	$45,343	$0	$45,343
SCEG	Land & Facilities Management	5560	$18,690	$0	$18,690
SCEG	Land & Facilities Management	5630	$20,156	$0	$20,156
SCEG	Land & Facilities Management	5660	$120,247	$0	$120,247
SCEG	Land & Facilities Management	5690	$35,330	$0	$35,330
SCEG	Land & Facilities Management	5700	$37,918	$0	$37,918
SCEG	Land & Facilities Management	5710	$27,089	$0	$27,089
SCEG	Land & Facilities Management	5800	$4,230	$0	$4,230
SCEG	Land & Facilities Management	5820	$1,050	$0	$1,050
SCEG	Land & Facilities Management	5830	$869	$0	$869
SCEG	Land & Facilities Management	5860	$1,947	$0	$1,947
SCEG	Land & Facilities Management	5880	$39,826	$0	$39,826
SCEG	Land & Facilities Management	5890	$241,643	$0	$241,643
SCEG	Land & Facilities Management	5900	$1,886	$0	$1,886
SCEG	Land & Facilities Management	5920	$106,602	$0	$106,602

SCEG	Land & Facilities Management	5930	$17,713	$0	$17,713
SCEG	Land & Facilities Management	5940	$30	$0	$30
SCEG	Land & Facilities Management	5970	$7,990	$0	$7,990
SCEG	Land & Facilities Management	5980	$2,391	$0	$2,391
SCEG	Land & Facilities Management	8410	$2,991	$0	$2,991
SCEG	Land & Facilities Management	8432	$17,249	$0	$17,249
SCEG	Land & Facilities Management	8439	$19,584	$0	$19,584
SCEG	Land & Facilities Management	8750	$6,075	$0	$6,075
SCEG	Land & Facilities Management	8760	$1,448	$0	$1,448
SCEG	Land & Facilities Management	8790	$2,850	$0	$2,850
SCEG	Land & Facilities Management	8800	$10,813	$0	$10,813
SCEG	Land & Facilities Management	8810	$233,292	$0	$233,292
SCEG	Land & Facilities Management	8870	$3,527	$0	$3,527
SCEG	Land & Facilities Management	9020	$8,535	$0	$8,535
SCEG	Land & Facilities Management	9030	$3,265	$0	$3,265
SCEG	Land & Facilities Management	9050	$13,831	$0	$13,831
SCEG	Land & Facilities Management	9080	$4,964	$0	$4,964
SCEG	Land & Facilities Management	9120	$2,895	$0	$2,895
SCEG	Land & Facilities Management	9200	$4,374	$1,140	$5,513
SCEG	Land & Facilities Management	9210	$65,634	$43,928	$109,561
SCEG	Land & Facilities Management	9260	$117,548	$254,853	$372,401
SCEG	Land & Facilities Management	9302	$3,550	$0	$3,550
SCEG	Land & Facilities Management	9310	$3,364,034	$508,338	$3,872,371
SCEG	Land & Facilities Management	9320	$69	$0	$69
SCEG	Land & Facilities Management	9350	$3,044,251	$2,362,334	$5,406,585
SCEG	Legal	1070	$4,324,829	$53,919	$4,378,748
SCEG	Legal	1180	$130,840	$7,373	$138,213
SCEG	Legal	1210	$1,240	$0	$1,240
SCEG	Legal	1823	$88,086	$0	$88,086
SCEG	Legal	1830	$45,333	$0	$45,333
SCEG	Legal	1832	$261,348	$0	$261,348
SCEG	Legal	1860	$998,002	$4,137	$1,002,138
SCEG	Legal	4081	$106,285	$121,786	$228,071
SCEG	Legal	4082	$2,198	$12	$2,210
SCEG	Legal	4160	$5,583	$0	$5,583
SCEG	Legal	4171	$8,988	$50	$9,037
SCEG	Legal	4210	$0	$4,643	$4,643
SCEG	Legal	4265	$322,781	$171,862	$494,643
SCEG	Legal	5617	$907	$0	$907
SCEG	Legal	7350	$6,103	$0	$6,103
SCEG	Legal	9040	($204)	$0	($204)
SCEG	Legal	9080	$14	$0	$14
SCEG	Legal	9200	$1,131,638	$1,666,667	$2,798,305
SCEG	Legal	9210	($44,918)	$564,890	$519,972
SCEG	Legal	9230	$4,051,177	$1,781,055	$5,832,232
SCEG	Legal	9250	$3,624,421	($91,874)	$3,532,547

SCEG	Legal	9260	$389,770	$602,994	$992,763
SCEG	Legal	9280	$945,334	$0	$945,334
SCEG	Legal	9302	$0	$1,832,179	$1,832,179
SCEG	Legal	9350	$5,046	$15,009	$20,055
SCEG	Marketing & Sales	1070	$65,806	$36,350	$102,156
SCEG	Marketing & Sales	1180	$0	$4,971	$4,971
SCEG	Marketing & Sales	1823	$140,739	$0	$140,739
SCEG	Marketing & Sales	1860	$0	$2,789	$2,789
SCEG	Marketing & Sales	4081	$55,202	$42,399	$97,601
SCEG	Marketing & Sales	4082	$69,273	$4,384	$73,656
SCEG	Marketing & Sales	4160	$3,542,845	$54,560	$3,597,406
SCEG	Marketing & Sales	4171	$262,328	$15,835	$278,163
SCEG	Marketing & Sales	4210	$0	$3,130	$3,130
SCEG	Marketing & Sales	4265	$1,518,618	$34,285	$1,552,903
SCEG	Marketing & Sales	5660	$2,058	$0	$2,058
SCEG	Marketing & Sales	9110	$1,325	$0	$1,325
SCEG	Marketing & Sales	9120	$164,096	($1,108)	$162,989
SCEG	Marketing & Sales	9130	$0	($3,082)	($3,082)
SCEG	Marketing & Sales	9160	$261,858	$0	$261,858
SCEG	Marketing & Sales	9200	$370,516	$611,561	$982,077
SCEG	Marketing & Sales	9210	$7,317	$36,195	$43,511
SCEG	Marketing & Sales	9230	$0	$4,132	$4,132
SCEG	Marketing & Sales	9260	$206,897	$302,290	$509,187
SCEG	Marketing & Sales	9280	$0	($621)	($621)
SCEG	Marketing & Sales	9301	$0	($841)	($841)
SCEG	Marketing & Sales	9302	$41,264	$47,091	$88,354
SCEG	Marketing & Sales	9310	$2,292	$4,592	$6,883
SCEG	Marketing & Sales	9320	$0	$78	$78
SCEG	Procurement	1070	$766,936	$36,559	$803,494
SCEG	Procurement	1080	$814	$0	$814
SCEG	Procurement	1180	$300,718	$4,999	$305,717
SCEG	Procurement	1630	$254,102	$0	$254,102
SCEG	Procurement	1860	$0	$2,805	$2,805
SCEG	Procurement	4081	$57,378	$54,310	$111,689
SCEG	Procurement	4082	$0	$231	$231
SCEG	Procurement	4171	$0	$888	$888
SCEG	Procurement	4210	$0	$3,148	$3,148
SCEG	Procurement	4265	$13	$25,790	$25,804
SCEG	Procurement	5930	$0	$0	$0
SCEG	Procurement	9120	$0	$182	$182
SCEG	Procurement	9200	$806,787	$779,469	$1,586,256
SCEG	Procurement	9210	$8,557	$70,701	$79,258
SCEG	Procurement	9230	$0	$17,896	$17,896
SCEG	Procurement	9260	$215,474	$341,106	$556,580
SCEG	Procurement	9302	$0	$64,536	$64,536
SCEG	Procurement	9310	$13,641	$0	$13,641

SCEG	Public Affairs	1070	$366,630	$36,532	$403,162
SCEG	Public Affairs	1180	$0	$4,996	$4,996
SCEG	Public Affairs	1823	$2,169	$0	$2,169
SCEG	Public Affairs	1860	$0	$2,803	$2,803
SCEG	Public Affairs	4081	$59,717	$28,843	$88,560
SCEG	Public Affairs	4082	$54,826	$33,440	$88,266
SCEG	Public Affairs	4171	$206,364	$124,970	$331,333
SCEG	Public Affairs	4210	$0	$3,146	$3,146
SCEG	Public Affairs	4261	$1,619,079	$402,524	$2,021,603
SCEG	Public Affairs	4264	$1,591,728	$753,277	$2,345,005
SCEG	Public Affairs	4265	$1,374,269	$138,963	$1,513,232
SCEG	Public Affairs	9010	$165	$0	$165
SCEG	Public Affairs	9100	$0	($476)	($476)
SCEG	Public Affairs	9200	$842,460	$389,997	$1,232,457
SCEG	Public Affairs	9210	$517,937	$194,652	$712,588
SCEG	Public Affairs	9230	$60	$0	$60
SCEG	Public Affairs	9260	$223,009	$228,764	$451,773
SCEG	Public Affairs	9302	$0	$728	$728
SCEG	Public Affairs	9310	$4,297	$24,560	$28,857
SCEG	Public Affairs	9350	$0	$166	$166
SCEG	Regulatory	1070	$860,984	$22,990	$883,974
SCEG	Regulatory	1180	$0	$3,144	$3,144
SCEG	Regulatory	1823	$64,916	$0	$64,916
SCEG	Regulatory	1860	$0	$1,764	$1,764
SCEG	Regulatory	4081	$90,072	$19,924	$109,996
SCEG	Regulatory	4082	$83	$273	$356
SCEG	Regulatory	4160	$120	$3,978	$4,098
SCEG	Regulatory	4171	$1,353	$1,024	$2,377
SCEG	Regulatory	4210	$0	$1,980	$1,980
SCEG	Regulatory	4265	$3,832	$7,418	$11,250
SCEG	Regulatory	9200	$1,004,015	$278,125	$1,282,140
SCEG	Regulatory	9210	$37,549	$13,679	$51,228
SCEG	Regulatory	9230	$462,053	$0	$462,053
SCEG	Regulatory	9260	$335,479	$163,176	$498,655
SCEG	Regulatory	9280	$310,874	$14	$310,888
SCEG	Regulatory	9310	$9,382	$0	$9,382
SCEG	Regulatory	9350	$0	$459	$459
SCEG	Strategic Planning	1070	$314,383	$31,174	$345,557
SCEG	Strategic Planning	1180	$488	$4,259	$4,746
SCEG	Strategic Planning	1840	$2,036	$349	$2,385
SCEG	Strategic Planning	1860	$0	$2,343	$2,343
SCEG	Strategic Planning	4081	$103,250	$33,370	$136,619
SCEG	Strategic Planning	4210	$0	$2,630	$2,630
SCEG	Strategic Planning	4265	$2,951	$12,223	$15,174
SCEG	Strategic Planning	5240	$773,106	$0	$773,106
SCEG	Strategic Planning	9200	$1,461,362	$487,367	$1,948,729

SCEG	Strategic Planning	9210	$285,596	$78,351	$363,947
SCEG	Strategic Planning	9260	$381,682	$245,476	$627,158
SCEG	Strategic Planning	9280	$9,272	$0	$9,272
SCEG	Strategic Planning	9302	$656,806	$0	$656,806
SCEG	Strategic Planning	9310	$11,044	$446	$11,490
	Grand Total		$212,101,090	$79,767,056	$291,868,147

Incentive compensation costs are included in the Employee Services category.

The Financial Services category includes depreciation, property taxes, accrued payroll and other costs recorded at a corporate level by SCANA Services, Inc.

Allocated costs billed from SCANA Services, Inc. are billed using one of the approved methodologies described below.

1. Information Systems Charge-back Rates - Rates for services, including but not limited to Software, Consulting, Mainframe, Midtier and Network Connectivity Services, are based on the costs of labor, materials and Information Services overheads related to the provision of each service. Such rates are applied based on the specific equipment employed and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

2. Margin Revenue Ratio - "Margin" is equal to the excess of sales revenues over the applicable cost of sales, i.e., cost of fuel for generation and gas for resale. The numerator is equal to margin revenues for a specific Client Entity and the denominator is equal to the combined margin revenues of all the applicable Client Entities. This ratio is evaluated annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, based on results of operations for a subsequent twelve-month period, as may be required due to significant changes.

3. Number of Customers Ratio - A ratio based on the number of customers served by each subsidiary or operating unit. This ratio is determined annually based on actual number of customers and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

4. Number of Employees Ratio - A ratio based on the number of employees benefiting from the performance of a service. This ratio is determined annually based on actual counts of applicable employees and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

5. Three-Factor Formula - This formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

6. Modified Three-Factor Method - A ratio for the allocation of non-directly assigned corporate governance costs. The Modified Three-Factor Method provides for an allocation of costs to the principal holding company; the Three-Factor Method does not. The formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues. For the purpose of the Modified Three-Factor Method, the dividends resulting from operations of the subsidiaries are used as a proxy for revenues for the principal holding company.

7. Telecommunications Charge-back Rates - Rates for use of telecommunications services other than those encompassed by Information Systems Charge-back Rates are based on the costs of labor, materials, outside services and Telecommunications overheads. Such rates are applied based on the specific equipment employment and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

8. Gas Sales Ratio - A ratio based on the actual number of dekatherms of natural gas sold by the applicable gas distribution or marketing operations. This ratio is determined annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, as may be required due to significant changes.

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Amount based on measured usage of assets to include computer resource usage, margin revenues, three-factor formula, number of customers and number of employees.

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