THIS FILING IS		
Item 1: [X] 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** 2016/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 1,144 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 150 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 2016/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* (803) 217-7416	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

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 Jimmy E. Addison	03 Signature Jimmy E. Addison	04 Date Signed *(Mo, Da, Yr)* 04/13/2017
02 Title Executive Vice President and CFO		

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 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 2016/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	106(b) - NA
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	NA
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NA
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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".

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		

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	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 2016/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.

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 Carolina Fuel Company, Inc.	Acquires, owns, provides	None	
2		financing for and sells at		
3		cost to 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 2016/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.

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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 Virginia 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 and		
17		utilize nuclear material and		
18		atomic energy. Operated a		
19		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. Other members include AJG Coal, Inc. and BSW Refined Coal.

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 2016/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 Officer	Kevin B. Marsh	1,038,607
3	Chief Operating Officer and President of Generation		
4	and Transmission	Stephen A. Byrne	631,296
5	President of Retail Operations	W. Keller Kissam	384,681
6	President of Gas Operations	D. Russell Harris	220,399
7	Executive Vice President and		
8	Chief Financial Officer	Jimmy E. Addison	473,624
9	Senior Vice President - Risk Management and		
10	Corporate Compliance (Effective 1/16)	Sarena D. Burch	228,965
11	Senior Vice President, General Counsel		
12	and Assistant Secretary	Ronald T. Lindsay	289,351
13	Senior Vice President Administration (Through 11/16)		
14	Senior Vice President of Special Projects		
15	(Effective 11/16, Retired 12/16)	Martin K. Phalen	293,843
16	Chief Information Officer (Through 2/16) Vice President		
17	and Chief Information Officer (Through 11/16)		
18	Senior Vice President		
19	Administration (Effective 11/16)	Randal M. Senn	250,198
20	Senior Vice President and Chief Nuclear Officer	Jeffrey B. Archie	383,751
21	Senior Vice President of Economic Development,		
22	Governmental & Regulatory Affairs	Kenneth R. Jackson	257,328
23	Vice President of Governmental Affairs	Henry E. Barton, Jr.	137,737
24	Vice President of Human Resources	Annmarie C. Higgins	216,508
25	Vice President of Marketing and Communications	Catherine B. Love	170,028
26	Vice President of Electric Operations	William J. Turner, III	216,527
27	Vice President of Gas Operations	Felicia R. Howard	218,414
28	Vice President of Gas Services	M. Shaun Randall	91,111
29	Vice President of Fossil Hydro	James M. Landreth	256,883
30	Vice President of Customer Relations and		
31	Renewables	Daniel F. Kassis	223,541
32	Vice President of Customer Service	Samuel L. Dozier	175,626
33	Vice President of SCANA Support		
34	Services (Effective 11/16)	Cedric F. Green	149,563
35	Vice President of Electric Transmission	Pandelis N. Xanthakos	180,814
36	Vice President of New Nuclear		
37	Operations (Through 11/16) Vice President		
38	Nuclear Construction and Startup (Effective 11/16)	Ronald A. Jones	300,410
39	Vice President of Nuclear Operations (Through 1/16)		
40	Vice President of Nuclear Support Services		
41	Services (Through 11/16) Vice President of		
42	Nuclear Operations Units 2/3 (Effective 11/16)	Thomas D. Gatlin	307,110
43	Vice President of Nuclear Operations (Effective 1/16)	George A. Lippard, III	254,236
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 2016/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 Financial		
2	Administration (Retired 6/16)	Carlette L. Walker	143,499
3	Treasurer and Risk Management		
4	Officer (Through 2/16) Vice President and		
5	Treasurer (Effective 2/16)	Mark R. Cannon	190,936
6	Secretary (Through 2/16) Vice President and		
7	Secretary (Effective 2/16)	Gina S. Champion	181,652
8	Vice President of Finance (Effective 11/16)		
9	and Treasurer (Effective 3/17)	Iris N. Griffin	105,957
10	Controller (Through 2/16) Vice President and		
11	Controller (Effective 2/16)	James E. Swan, IV	216,946
12	Vice President of SCANA Support		
13	Services (Through 11/16) Vice President and Chief		
14	Information Officer (Effective 11/16)	Stacy O. Shuler, Jr.	178,531
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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 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 2016/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***	Boston, Massachusetts
7	L. M. Miller	Great Falls, Virginia
8	J. W. Roquemore***	Orangeburg, South Carolina
9	M. K. Sloan	Durham, North Carolina
10	H.C. Stowe***	Pawley's Island, South Carolina
11	A. Trujillo	Atlanta, Georgia
12	K. B. Marsh, Chairman	
13	and Chief Executive Officer of	
14	SCANA Corporation and SCE&G**	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 2016/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 8	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 2016/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	20160513-5152	05/13/2016	ER10-516	Annual Update Infomational 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 2016/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
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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 2016/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. Three 20-year municipal electric and gas franchise agreements were established during the second quarter of 2016 without payment of consideration.

One 20-year municipal electric and gas franchise agreement was established during the third quarter of 2016 without payment of consideration.

One 20-year municipal electric franchise agreement was established during the fourth quarter of 2016 without payment of consideration.

2. None

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:

12/31/2016	12/31/2015
$804,321,000	$420,225,000

Such short-term borrowings have been authorized by FERC (Docket Nos. ES14-48-000 and ES16-51-000).

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&Gs construction program, to finance capital expenditures, and for general corporate purposes.

Such long-term borrowings have been authorized by the SCPSC (Docket Nos. 2013-132-E and 2010-317-E).

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 2016:

Sharon A. Decker and Gregory E. Aliff were appointed to the Company’s Board of Directors.

Harold C. Stowe retired from the Company's Board of Directors.

Sarena D. Burch, formerly Senior Vice President - Fuel Procurement & Asset Management, was appointed Senior Vice President - Risk Management & Corporate Compliance.

Thomas D. Gatlin, formerly Vice President of Nuclear Operations, was appointed Vice President of Nuclear Support Services, January 2016 - November 2016. Effective November 2016, Mr. Gatlin was appointed Vice President of Nuclear Operations Units 2/3.

George A. Lippard, III was appointed Vice President of Nuclear Operations.

James E. Swan, IV, Controller, was named Vice President and Controller.

Randall M. Senn, Chief Information Officer, was named Vice President and Chief Information Officer February 2016 - November 2016. Effective November 2016, Mr. Senn was appointed Senior Vice President Administration.

Gina S. Champion, Secretary, was named Vice President and Secretary.

Mark R. Cannon, Treasurer and Risk Management Officer, was named Vice President and Treasurer. Mr. Cannon retired effective February 28, 2017.

Carlette L. Walker, Vice President of Nuclear Financial Administration, retired.

Martin K. Phalen, Senior Vice President Administration, assumed duties as Senior Vice President of Special Projects until his December 31, 2016 retirement date.

Stacy O. Shuler, Jr. Vice President of SCANA Support Services, was appointed Vice President and Chief Information Officer.

Cedric F. Green was appointed Vice President of SCANA Support Services.

Iris N. Griffin was appointed Vice President of Finance. On March 1, 2017, Mrs. Griffin assumed duties of Treasurer in addition to her responsibilities as Vice President of Finance.

Ronald A. Jones, formerly Vice President of New Nuclear Operations was appointed Vice President of Nuclear Construction and Startup.

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 2016/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	10,808,517,861	10,456,789,235
3	Construction Work in Progress (107)	200-201	4,808,038,309	3,990,834,928
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		15,616,556,170	14,447,624,163
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,271,191,389	4,149,318,951
6	Net Utility Plant (Enter Total of line 4 less 5)		11,345,364,781	10,298,305,212
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	144,178,325	81,161,353
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		72,615,225	116,928,535
9	Nuclear Fuel Assemblies in Reactor (120.3)		223,723,883	223,038,612
10	Spent Nuclear Fuel (120.4)		673,993,828	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	843,261,889	786,794,670
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		271,249,372	308,327,658
14	Net Utility Plant (Enter Total of lines 6 and 13)		11,616,614,153	10,606,632,870
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		69,793,932	68,776,649
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,064,999	1,108,780
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,856,380	1,394,608
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)		61,516	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)		122,840,806	114,983,724
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		70,585,791	4,539,044
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		265,073,426	188,646,761
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		160,445,414	127,896,448
36	Special Deposits (132-134)		187,012	12,236,393
37	Working Fund (135)		60,525	62,025
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		249,194,592	218,883,482
41	Other Accounts Receivable (143)		155,928,285	201,397,221
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,239,931	2,964,230
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		4,731,796	9,450,009
45	Fuel Stock (151)	227	46,289,912	57,600,683
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	134,522,151	128,029,866
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	640,580	656,143

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 2016/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	351
55	Gas Stored Underground - Current (164.1)		11,124,020	15,144,464
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		7,705,351	8,250,772
57	Prepayments (165)		87,029,102	82,477,535
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		121,727	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		117,626,653	101,515,765
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		70,585,791	14,895,948
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		70,585,791	4,539,044
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)		972,367,189	970,993,831
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		35,470,866	31,259,886
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	118,538,678	126,656,202
72	Other Regulatory Assets (182.3)	232	1,903,279,248	1,703,585,141
73	Prelim. Survey and Investigation Charges (Electric) (183)		709,896	198,470
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	165,241,815	84,634,918
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)		15,116,379	16,258,765
82	Accumulated Deferred Income Taxes (190)	234	289,147,004	276,025,196
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,527,503,886	2,238,618,578
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		15,381,558,654	14,004,892,040

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 2016/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	2,188,167,716
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	2,481,211,937	2,265,470,454
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)	-2,973,265	-2,770,003
16	Total Proprietary Capital (lines 2 through 15)		5,338,576,131	5,023,037,910
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,928,770,000	4,428,770,000
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	265,579	100,185,967
22	Unamortized Premium on Long-Term Debt (225)		24,319,529	24,981,816
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		24,038,677	22,751,632
24	Total Long-Term Debt (lines 18 through 23)		4,929,316,431	4,531,186,151
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		20,678,011	12,477,819
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		7,859,531	5,355,089
29	Accumulated Provision for Pensions and Benefits (228.3)		233,863,772	186,867,019
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		3,371,455	21,708,781
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		509,434,012	476,223,696
35	Total Other Noncurrent Liabilities (lines 26 through 34)		775,206,781	702,632,404
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		804,321,000	420,225,000
38	Accounts Payable (232)		233,861,353	450,763,775
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		90,213,959	77,601,960
41	Customer Deposits (235)		60,283,425	57,087,060
42	Taxes Accrued (236)	262-263	190,023,234	337,368,808
43	Interest Accrued (237)		66,075,852	64,981,070
44	Dividends Declared (238)		77,500,000	72,300,000
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 2016/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)		8,495,957	8,534,964
48	Miscellaneous Current and Accrued Liabilities (242)		64,185,149	71,869,175
49	Obligations Under Capital Leases-Current (243)		5,341,366	3,860,666
50	Derivative Instrument Liabilities (244)		29,862,614	54,566,151
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		3,371,455	21,708,781
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)		1,626,792,454	1,597,449,848
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	22,188,300	23,580,500
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	60,685,179	69,255,823
60	Other Regulatory Liabilities (254)	278	238,845,948	147,235,196
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	12,039,300	12,361,300
63	Accum. Deferred Income Taxes-Other Property (282)		2,003,667,530	1,532,935,108
64	Accum. Deferred Income Taxes-Other (283)		374,240,600	365,217,800
65	Total Deferred Credits (lines 56 through 64)		2,711,666,857	2,150,585,727
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		15,381,558,654	14,004,892,040

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 2016/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	2,986,197,254	2,929,818,797		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,346,876,575	1,397,711,033		
5	Maintenance Expenses (402)	320-323	147,981,511	150,487,404		
6	Depreciation Expense (403)	336-337	254,702,412	246,035,441		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	8,989,523	9,373,615		
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)		5,655,182	1,061,940		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	227,416,255	210,726,419		
15	Income Taxes - Federal (409.1)	262-263	-149,609,400	213,774,190		
16	- Other (409.1)	262-263	-19,006,840	31,833,545		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	673,023,500	279,501,015		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	255,031,632	294,732,032		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,392,200	-2,371,100		
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)		2,258,526,746	2,262,323,330		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		727,670,508	667,495,467		

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
2,619,373,876	2,557,104,822	366,823,378	372,713,975			2
						3
1,100,037,139	1,143,617,023	246,839,436	254,094,010			4
138,310,848	142,330,167	9,670,663	8,157,237			5
228,393,600	220,178,807	26,308,812	25,856,634			6
						7
8,037,130	8,443,725	952,393	929,890			8
854,201	854,201	6,217	6,217			9
18,061,442	18,061,442					10
						11
5,655,182	1,061,940					12
						13
200,637,124	185,840,612	26,779,131	24,885,807			14
-144,978,100	212,968,289	-4,631,300	805,901			15
-18,767,040	31,801,445	-239,800	32,100			16
641,198,000	253,565,716	31,825,500	25,935,299			17
241,225,732	281,879,832	13,805,900	12,852,200			18
-1,279,600	-1,285,700	-112,600	-1,085,400			19
						20
						21
						22
						23
						24
1,934,934,194	1,935,557,835	323,592,552	326,765,495			25
684,439,682	621,546,987	43,230,826	45,948,480			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 2016/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)		727,670,508	667,495,467		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		7,423,708	7,102,682		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		4,907,731	4,357,022		
33	Revenues From Nonutility Operations (417)		92,172			
34	(Less) Expenses of Nonutility Operations (417.1)		673,974	613,039		
35	Nonoperating Rental Income (418)		150,223	123,848		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,095,182	-4,827,566		
37	Interest and Dividend Income (419)		5,458,249	3,795,907		
38	Allowance for Other Funds Used During Construction (419.1)		26,082,377	24,828,339		
39	Miscellaneous Nonoperating Income (421)		16,068,854	16,450,885		
40	Gain on Disposition of Property (421.1)		621,436	4,048,536		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		46,220,132	46,552,570		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		33,834	33,834		
45	Donations (426.1)		3,245,411	8,408,608		
46	Life Insurance (426.2)		28,544	58,652		
47	Penalties (426.3)			-49,866		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,535,302	2,622,234		
49	Other Deductions (426.5)		8,827,081	9,538,330		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		13,670,172	20,611,792		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	660,927	377,023		
53	Income Taxes-Federal (409.2)	262-263	-6,033,035	-7,631,612		
54	Income Taxes-Other (409.2)	262-263	485,364	-533,991		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	5,673,000	6,674,300		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	7,892,900	3,608,029		
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)		-7,106,644	-4,722,309		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		39,656,604	30,663,087		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		253,679,997	231,189,035		
63	Amort. of Debt Disc. and Expense (428)		2,940,265	2,844,059		
64	Amortization of Loss on Reaquired Debt (428.1)		1,142,386	1,429,139		
65	(Less) Amort. of Premium on Debt-Credit (429)		662,287	637,373		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		6,296,983	6,818,827		
68	Other Interest Expense (431)		9,290,728	4,737,747		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		18,052,443	14,003,579		
70	Net Interest Charges (Total of lines 62 thru 69)		254,635,629	232,377,855		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		512,691,483	465,780,699		
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)		512,691,483	465,780,699		

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

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: h

Includes depreciation charges of $7,782,561, amortization charges of $2,192,696 and property taxes of $1,927,680 billed from SCANA Services.

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

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.: 4 Column: j

Includes depreciation charges of $861,282, amortization charges of $190,162 and property taxes of $167,477 billed from SCANA Services.

Schedule Page: 114 Line No.: 39 Column: d

In SCPSC Docket No. 2014-44-E, the SCPSC authorized the Company to utilize interest rate derivative settlement gains to offset the ongoing DSM Lost Revenues through April 2015. Accordingly, during 2015 the Company recognized $5,189,042 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric 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 2016/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)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,193,031,209	2,009,500,783
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)		516,786,665	470,608,265
17	Appropriations of Retained Earnings (Acct. 436)			
18	See Note 3 to Financial Statements	215.1	-6,554,471	(4,750,273)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-6,554,471	(4,750,273)
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	-296,950,000	(277,500,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-296,950,000	(277,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-4,095,182	(4,827,566)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,402,218,221	2,193,031,209
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		78,993,716	72,439,245
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		78,993,716	72,439,245
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,481,211,937	2,265,470,454
	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)		-4,095,182	(4,827,566)
51	(Less) Dividends Received (Debit)			
52	Funded Equity Method losses		4,095,182	4,827,566
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 2016/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)	512,691,483	465,780,699
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	254,816,443	246,203,515
5	Amortization of Utility Plant and Acquisition Adjustment	9,883,775	10,267,867
6	Amortization - DER, Muni Franchise, Unrecovered Plt, & OCI	23,886,561	19,314,459
7	Amortization of Nuclear Fuel	56,467,219	45,687,791
8	Deferred Income Taxes (Net)	466,437,214	-9,862,347
9	Investment Tax Credit Adjustment (Net)	-1,392,200	-2,371,100
10	Net (Increase) Decrease in Receivables	-106,019,875	138,604,283
11	Net (Increase) Decrease in Inventory	-33,502,669	-38,218,180
12	Net (Increase) Decrease in Allowances Inventory	15,563	19,389
13	Net Increase (Decrease) in Payables and Accrued Expenses	-133,163,069	161,668,383
14	Net (Increase) Decrease in Other Regulatory Assets	-58,647,509	34,579,717
15	Net Increase (Decrease) in Other Regulatory Liabilities	35,920,913	12,933,219
16	(Less) Allowance for Other Funds Used During Construction	26,082,377	24,828,339
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-92,480,187	-19,891,407
19	Discount / Premium on Long-Term Debt	-98,464	-125,075
20	Carrying Cost Recovery	-16,654,733	-12,330,778
21	(Gain) / Loss on Disposition of Assets	-1,315,217	-4,379,390
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	890,762,871	1,023,052,706
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,332,925,131	-943,892,487
27	Gross Additions to Nuclear Fuel	-71,594,316	-76,368,193
28	Gross Additions to Common Utility Plant	-11,090,849	-13,825,300
29	Gross Additions to Nonutility Plant	-613,377	-1,028,958
30	(Less) Allowance for Other Funds Used During Construction	-26,082,377	-24,828,339
31	Other (provide details in footnote):		
32	Salvage Received	3,331,278	7,761,255
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,386,810,018	-1,002,525,344
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	46,858,251	7,986,126
39	Investments in and Advances to Assoc. and Subsidiary Companies	-5,345,411	-4,061,149
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Settlement of Interest Rate Swaps		10,278,883
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 2016/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 Utility Money Pool		-9,420,000
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	80,000,000
54	Other Investments	10,391,301	84,796,178
55	Settlement of Interest Rate Swaps	-113,015,868	-262,844,303
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,438,501,745	-1,095,789,609
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	500,000,000	500,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Contributions from Parent	100,000,000	204,414,449
66	Net Increase in Short-Term Debt (c)	384,096,000	
67	Other (provide details in footnote):		
68	Borrowings from Utility Money Pool		521,400,000
69	Deferred Financing Costs / Long-Term Debt Issuance Costs	-7,112,918	-10,729,017
70	Cash Provided by Outside Sources (Total 61 thru 69)	976,983,082	1,215,085,432
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-104,946,742	-3,880,073
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Borrowings from Utility Money Pool		-538,187,861
78	Net Decrease in Short-Term Debt (c)		-288,422,000
79	Return of Capital Contributions to Parent		-3,501,500
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-291,750,000	-277,700,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	580,286,340	103,393,998
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	32,547,466	30,657,095
87			
88	Cash and Cash Equivalents at Beginning of Period	127,958,473	97,301,378
89			
90	Cash and Cash Equivalents at End of period	160,505,939	127,958,473

Schedule Page: 120 Line No.: 14 Column: c

Certain prior period amounts, related to non-cash changes in fair value of interest rate swaps, have been reclassified within Operating Activities to conform to the current period presentation. Specifically, ($180,016,685) was reclassified from Net (Increase) Decrease in Other Regulatory Assets and ($4,617,067) was reclassified from Net Increase (Decrease) in Other Regulatory Liabilities, with an offsetting reclassification in Other. These reclassifications had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the Statement of Cash Flows.

Schedule Page: 120 Line No.: 15 Column: c

Certain prior period amounts, related to non-cash changes in fair value of interest rate swaps, have been reclassified within Operating Activities to conform to the current period presentation. Specifically, ($180,016,685) was reclassified from Net (Increase) Decrease in Other Regulatory Assets and ($4,617,067) was reclassified from Net Increase (Decrease) in Other Regulatory Liabilities, with an offsetting reclassification in Other. These reclassifications had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the Statement of Cash Flows.

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

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.: 18 Column: c

Includes $141,794 for changes in the Company's net postretirement benefit obligation, ($13,798,937) for Prepayments, ($27,988,645) for Cost of Removal, $2,272,187 for Customer Deposits, and various other Balance Sheet changes not presented as separate line items.

Certain prior period amounts, related to non-cash changes in fair value of interest rate swaps, have been reclassified within Operating Activities to conform to the current period presentation. Specifically, ($180,016,685) was reclassified from Net (Increase) Decrease in Other Regulatory Assets and ($4,617,067) was reclassified from Net Increase (Decrease) in Other Regulatory Liabilities, with an offsetting reclassification in Other. These reclassifications had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the Statement of Cash Flows.

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

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.: 26 Column: c

For the twelve months ended December 31, 2015, the Company added $3,072,241 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($2,098,473) 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, 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.: 28 Column: c

For the twelve months ended December 31, 2015, the Company added $564,796 to its Common Utility Plant Property Account (118) and reduced the same account by ($399,018) 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, 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.: 29 Column: c

For the twelve months ended December 31, 2015, the Company added $2,516,410 to its Nonutility Property Account (121) and reduced the same account by ($1,364,577) for capital leases in accordance with USoA General Instruction No. 20.

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

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

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

Nuclear Decommissioning Trust	($ 2,086,012)
Collateral Returned - Interest Rate Swaps	934,668,640
Collateral Posted - Interest Rate Swaps	(840,119,762)
Withdrawals from Like Kind Exchange Escrow Account	1,256,673
Deposits to Like Kind Exchange Escrow Account	(8,923,361)
Total	$ 84,796,178

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.

The basic financial statements shown on pages 110 through 122 are prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). The significant differences from the GAAP requirements are related to the classification of certain assets and liabilities to include the classification of the current portion of certain regulatory 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. In addition, the accounts of South Carolina Generating Company, Inc. (GENCO) are not consolidated herein, whereas they are so consolidated for GAAP reporting purposes.

These notes are based on the notes contained in South Carolina Electric & Gas Company's (SCE&G) Annual Report on Form 10-K filed with the United States Securities and Exchange Commission (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, 2016 up to February 24, 2017, the date that SCE&G's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 13, 2017. 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 Corporation (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 South Carolina Fuel Company, Inc. (Fuel Company) which is considered to be a variable interest entity and, accordingly, SCE&G's financial statements include the accounts of SCE&G and Fuel Company. The equity interest in Fuel Company is 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.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current presentation, as follows:

Statements of Cash Flows - Non-cash changes in fair value of interest rate swaps were reclassified as an offset to the changes in certain assets and liabilities section within the reconciliations of Net Income to Net Cash Provided From Operating Activities as follows:

	December 31,	
Millions of dollars	2015	2014
Derivative financial instruments	$ (174)	$ 207
Regulatory assets	179	(234)
Regulatory liabilities	4	(29)
Other assets	(15)	32
Other liabilities	6	24

In addition, due to insignificance, the caption for Losses from equity method investments has been eliminated, and the amounts have been reclassified and included within the caption of Changes in Other assets.

The reclassifications above had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the consolidated statements of cash flows.

Statements of Comprehensive Income - Operating revenues and operating expenses from transactions with nonconsolidated affiliates are presented separately. A detail of such transactions is included in Note 11.

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 allowance for funds used during construction (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 4.7% for 2016, 5.6% for 2015, and 6.5% for 2014. 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. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the Public Service Commission of South Carolina (SCPSC) and further described in Note 2. The composite weighted average depreciation rates for utility plant assets were 2.56% in 2016, 2.55% in 2015 and 2.85% in 2014.

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. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the United States Department of Energy (DOE) under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of V. C. Summer Nuclear Station (Summer Station) Unit 1. In addition, SCE&G will jointly own and will be the operator of the Nuclear Units 2 and 3 (New Units) being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2016		2015	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.3 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 634.4 million	—	$ 620.4 million	—
Construction work in progress	$ 167.7 million	$ 4.2 billion	$ 214.6 million	$ 3.4 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from South Carolina Public Service Authority (Santee Cooper) for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $76.2 million at December 31, 2016 and $178.8 million at December 31, 2015.

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, 2016, and 2015, SCE&G incurred $19.5 million and $16.5 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 $26.8 million for the Fall 2015 outage and $1.8 million in 2016 in preparation for the Spring 2017 outage.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station 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 Summer Station 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 SCE&G and affiliate personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance 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 Summer Station 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 and treasury bills.

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. Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of 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 they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including SCE&G, in the form of capital contributions.

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 in 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. 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.

Income Statement Presentation

Revenues and expenses of SCE&G's regulated activities (including those activities of segments described in Note 12) are presented within Operating Income, 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. Unbilled revenues totaled $117.6 million at December 31, 2016 and $101.5 million at December 31, 2015.

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 hearings. 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 hearings.

SCE&G customers subject to a Purchased Gas Adjustment (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.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a Weather Normalization Adjustment 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

In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance for revenue arising from contracts with customers that supersedes most earlier revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. SCE&G expects to adopt this guidance when required in the first quarter of 2018. The guidance permits adoption using a retrospective method, with options to elect certain practical expedients, or recognition of a cumulative effect in the year of initial adoption. SCE&G has not determined which method of adoption will be employed or what practical expedients may be elected. SCE&G has not determined the impact this guidance will have on its financial statements. However, the identification of implementation project team members and the analysis of contracts with customers to which the guidance might be applicable, particularly large customer contracts, have begun. In addition, activities of the FASB's Transition Resource Group for Revenue Recognition are being monitored, particularly as they relate to the required treatment under the standard of contributions in aid of construction, alternative revenue programs and the collectibility of revenue of utilities subject to rate regulation.

In May 2015, the FASB issued accounting guidance removing the requirement to categorize within the fair value hierarchy investments for which fair values are estimated using the Net Asset Value (NAV) practical expedient. Disclosures about investments in certain entities that calculate NAV per share are limited under this guidance to those investments for which the entity has elected to estimate the fair value using the NAV practical expedient. SCE&G elected to adopt this guidance on a retrospective basis. The adoption resulted in the reclassification of fair value related to the pension plan's investment in the common collective trust, joint venture interest, and limited partnership as of December 31, 2015. See Note 8.

In July 2015, the FASB issued accounting guidance intended to simplify the measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. SCE&G expects to adopt this guidance in the first quarter of 2017 and does not expect it to have a significant impact on its financial statements.

In January 2016, the FASB issued accounting guidance that will change how entities measure certain equity investments and financial liabilities, among other things. SCE&G expects to adopt this guidance when required in the first quarter of 2018 and has determined adoption of this guidance will not have a significant impact on its financial statements.

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. The guidance will be effective for years beginning in 2019. SCE&G has not determined what impact this guidance will have on its financial statements. However, the identification of implementation project team members and the initial identification and analysis of leasing and related contracts to which the guidance might be applicable have begun. In addition, SCE&G has begun evaluating certain third party software tools that may assist with this implementation and ongoing compliance.

In March 2016, the FASB issued accounting guidance changing how companies account for certain aspects of share-based payments to employees. Entities will be required to recognize the income tax effects of awards in the income statement when the awards vest or are settled. SCE&G adopted this guidance in the fourth quarter of 2016 and determined, based on the nature of its share-based awards practices, the adoption had no impact on its financial statements.

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 is intended to result in certain 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 2016, the FASB issued accounting guidance to reduce diversity in cash flow classification related to certain transactions. SCE&G expects to adopt this guidance when required in the first quarter of 2018 and does not anticipate that its adoption will impact its financial statements.

In October 2016, the FASB issued accounting guidance related to the tax effects of intra-entity asset transfers of assets other than inventory. An entity will be required to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. SCE&G expects to adopt this guidance in the first quarter 2017 and it is not expected to have a material impact on its financial statements.

In November 2016, the FASB issued accounting guidance related to the presentation of restricted cash on the statement of cash flows. The guidance is effective for years beginning in 2018 and SCE&G expects no impact on its financial statements.

In January 2017, the FASB issued accounting guidance to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test. The same one-step impairment test will be applied to goodwill at all reporting units, even those with zero or negative carrying amounts. The guidance is effective for years beginning in 2020, though early adoption after January 1, 2017 is allowed. SCE&G has not determined when this guidance will be adopted but does not anticipate that adoption will have a material impact on its financial statements.

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.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments were fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act of 1982 (Nuclear Waste Act) for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the United States Court of Appeals for the District of Columbia (Court of Appeals), the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

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 a settlement agreement among SCE&G, Office of Regulatory Staff (ORS), and certain other parties concerning SCE&G's petition for approval to participate in a Distributed Energy Resource (DER) program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 Megawatts (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.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million ($.12 per share) in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million ($.06 per share) with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

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.

In October 2016, the SCPSC initiated its 2017 annual review of base rates for fuel costs. A public hearing for this annual review was held on April 6, 2017.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G removes from rate base certain deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G's weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $14.0 million and $9.5 million during 2016 and 2015, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these deferred income tax assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of demand reduction and energy efficiency programs (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
2016	First billing cycle of May	$37.6 million
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G's request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider is 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.

In January 2017, 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 the DSM Programs, along with an incentive to invest in such programs.

By order dated March 1, 2017, the SCPSC approved SCE&G's request to decrease its pension costs rider. The pension rider is designed to allow SCE&G to recover projected pension costs, net of previous over-collected balances, over a 12-month period beginning with the first billing cycle in May 2017.

Electric - Base Load Review Act (BLRA)

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity (ROE). The SCPSC has approved recovery of the following amounts.

Year	Increase	Effective for bills rendered on and after	Amount	Allowed ROE	
2016	2.7%	November 27	$64.4 million	10.50%	*
2015	2.6%	October 30	$64.5 million	11.00%	
2014	2.8%	October 30	$66.2 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 the New Units which were developed in connection with the Amendment, dated October 27, 2015 (October 2015 Amendment), to the Engineering, Procurement and Construction Agreement dated May 23, 2008 (EPC Contract). On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at 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 new nuclear construction from 10.5% to 10.25%. This revised ROE will 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 may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time. See also New Nuclear Construction in Note 10.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. The time period to file a Notice of Appeal of the SCPSC's decision with the South Carolina Supreme Court has expired for three of the four non-settling parties, and none of those parties have filed a Notice of Appeal. As for the remaining non-settling party, the time period for that party to file a Notice of Appeal has not yet expired, but as of April 13, 2017 (the filing date of this FERC Form 1 report), that party has not filed a Notice of Appeal.

Gas

The Natural Gas Rate Stabilization Act (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
2016	1.2% Increase	$4.1 million
2015	No change	—
2014	0.6% Decrease	$2.6 million

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, 2016, 2015 and 2014 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.

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. Other than 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 30, 2016	December 31, 2015
Regulatory Assets:		
Accumulated deferred income taxes	$ 293	$ 276
Asset Retirement Obligations (AROs) and related funding	388	370
Deferred employee benefit plan costs	308	294
Deferred losses on interest rate derivatives	611	526
Unrecovered plant	117	127
DSM Programs	59	61
Carrying costs on deferred tax assets related to nuclear construction	32	18
Environmental remediation costs	26	35
Deferred storm damage costs	20	—
Deferred costs related to uncertain tax position	15	—
Pipeline integrity management costs	6	4
Other	116	106
Total Regulatory Assets	$ 1,991	$ 1,817
Regulatory Liabilities:		
Asset removal costs	$ 502	$ 491
Deferred gains on interest rate derivatives	151	96
Other	14	18
Total Regulatory Liabilities	$ 667	$ 605

Accumulated deferred income tax liabilities that arise from utility operations that have not been included in customer rates are recorded as a regulatory asset. A substantial portion of these regulatory assets relates to depreciation and is expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station 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 110 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. In 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or 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, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

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 such 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 nuclear construction are calculated on accumulated deferred income tax assets associated with the New Units which are not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs will be amortized over ten years beginning in approximately 2020.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G, and are expected to be recovered over periods of up to approximately 18 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 represent 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 are expected to be recovered through utility rates following ultimate resolution of the claims. See also Note 5.

Pipeline integrity management costs represent costs incurred to comply with regulatory requirements related to natural gas pipelines located near moderate to high density populations. SCE&G began amortizing $1.9 million of such costs annually in

November 2015.

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

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

The SCPSC or the FERC has reviewed and approved through specific orders most 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 the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders. 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 or other changes in the regulatory environment or changes in accounting requirements, SCE&G could be required to write off 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.

3. COMMON EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2016 and December 31, 2015. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were issued and outstanding as of December 30, 2016 and December 31, 2015. All issued and outstanding shares of SCE&G's common and preferred stock are held by SCANA.

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 contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016 and 2015, retained earnings of approximately $79.0 million and $72.4 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	2016 Balance	2016 Rate	2015 Balance	2015 Rate
First Mortgage Bonds (secured)	2018 - 2065	$ 4,840	5.79%	$ 4,340	5.78%
Industrial and Pollution Control Bonds (a)	2028 - 2038	89	3.42%	89	3.42%
Nuclear Fuel Financing	2016	—	—%	100	0.78%
Other	2017 - 2027	26	2.76%	16	2.63%
Total debt		4,955		4,545	
Current maturities of long-term debt		(5)		(104)	
Unamortized premium, net		—		2	
Unamortized debt issuance costs		(35)		(31)	
Total long-term debt, net		$ 4,915		$ 4,412	

(a) Includes variable rate debt of $34.6 million at December 31, 2016 (rate of .76%) and 2015 (rate of .03%) which are hedged by fixed swaps.

On November 1, 2016, Fuel Company paid at maturity $100 million related to a nuclear fuel financing which had an imputed interest rate of 0.78%.

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.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale 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 $5 million in 2017, $555 million in 2018, $4 million in 2019, $4 million in 2020 and $32 million in 2021.

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, 2016, the Bond Ratio was 5.12.

Lines of Credit (LOC) and Short-Term Borrowings

At December 31, 2016 and 2015, 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		2016		2015
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)	$	804.3	$	420.2
Weighted average interest rate		1.04%		0.74%
Letters of credit supported by LOC	$	0.3	$	0.3
Available	$	595.4	$	979.5

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. The 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 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, 2015, SCE&G had money pool investments due from an affiliate of $9.0 million. On SCE&G's balance sheet, amounts due from an affiliate are included within Receivables-affiliated companies.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	**2016**	**2015**	**2014**
Current taxes:			
Federal	$ 49	$ 207	$ 39
State	12	31	(7)
Total current taxes	61	238	32
Deferred tax (benefit) expense, net:			
Federal	162	(9)	151
State	19	(3)	32
Total deferred taxes	181	(12)	183
Investment tax credits:			
Amortization of amounts deferred-state	—	(1)	(1)
Amortization of amounts deferred-federal	(2)	(2)	(3)
Total investment tax credits	(2)	(3)	(4)
Total income tax expense	$ 240	$ 223	$ 211

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	**2016**	**2015**	**2014**
Net income	$ 513	$ 466	$ 446
Income tax expense	240	223	211
Total pre-tax income	753	689	657
Income taxes on above at statutory federal income tax rate	264	241	230
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	25	23	20
State investment tax credits (less federal income tax effect)	(5)	(6)	(5)
Allowance for equity funds used during construction	(9)	(9)	(10)
Amortization of federal investment tax credits	(2)	(2)	(2)
Section 41 tax credits	—	1	(3)
Section 45 tax credits	(8)	(9)	(9)
Domestic production activities deduction	(23)	(18)	(7)
Other differences, net	(2)	2	(3)
Total income tax expense	$ 240	$ 223	$ 211

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

Millions of dollars	**2016**	**2015**
Deferred tax assets:		
Nondeductible accruals	$ 53	$ 52
Asset retirement obligation, including nuclear decommissioning	195	182
Financial instruments	—	2
Unamortized investment tax credits	14	15
Deferred fuel costs	17	7
Other	8	2
Total deferred tax assets	287	260
Deferred tax liabilities:		
Property, plant and equipment	$ 1,753	$ 1,546
Deferred employee benefit plan costs	92	85
Regulatory asset, asset retirement obligation	130	122
Regulatory asset, unrecovered plant	45	49
Demand side management costs	23	23
Prepayments	29	29
Other	49	41
Total deferred tax liabilities	2,121	1,895
Net deferred tax liability	$ 1,834	$ 1,635

SCE&G is included in the consolidated federal income tax returns of SCANA and files various applicable state and local income tax returns. The United States Internal Revenue Service (IRS) has completed examinations of the SCANA's federal returns through 2004, and the SCANA's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2015 as a result of claims discussed below in Changes in Unrecognized Tax Benefits. 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	**2016**	**2015**	**2014**
Unrecognized tax benefits, January 1	$ 49	$ 16	$ 3
Gross increases—uncertain tax positions in prior period	94	33	—
Gross decreases—uncertain tax positions in prior period	—	(2)	—
Gross increases—current period uncertain tax positions	207	2	13
Unrecognized tax benefits, December 31	$ 350	$ 49	$ 16

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under Internal Revenue Code (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 September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. 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 2015 income tax returns.

These income tax deductions and credits are 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 are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, SCE&G has recorded an unrecognized tax benefit of $350 million ($236 million, net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). If recognized, $17 million of the tax benefit would affect SCE&G's effective tax rate (see discussion below regarding deferral of benefits related to 2015 forward). It is reasonably possible that these unrecognized tax benefits may increase by an additional $292 million within the next 12 months as additional expenditures giving rise to pilot model tax benefits are incurred. It is also reasonably possible that these unrecognized tax benefits may decrease by $49 million within the next 12 months if the claims on the amended returns which are currently in appeals are resolved and that resolution were also applied to the 2013 and 2014 returns. No other material changes in the status of SCE&G's tax positions have occurred through December 31, 2016.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 income tax returns and the expectation of similar claims to be made in determining 2016's taxable income, SCE&G has recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, and expect that such (net) deferred costs, along with any interest (see below) and other related deferred costs, will be recoverable through customer rates in future years. SCE&G's current customer rates reflect the availability of domestic production activities deductions (see Note 2).

Estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 income tax returns has been deferred and is expected to be recoverable through customer rates in future years. See also Note 2. Otherwise, SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognize tax penalties within other expenses. In 2016, the amount recorded for such interest income is $1.8 million and interest expense is $0.9 million. Such amounts were not significant in 2015 or 2014. No amounts have been recorded for tax penalties for any periods 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 as cash flow hedges and fair value changes and settlement amounts related to them are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be amortized to interest expense or may be applied as otherwise directed by the SCPSC.

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, 2016	December 31, 2015
Not designated as hedging instruments	$ 1,285.0	$ 1,235.0

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, 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
As of December 31, 2015			
Not designated as hedging instruments			
Interest rate contracts			
	Other current assets	$ 10	—
	Other deferred debits and other assets	5	—
	Derivative financial instruments	—	$ 33
	Other deferred credits and other liabilities	—	22
Total		$ 15	$ 55

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, 2016			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2015			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2014			
Interest rate contracts	$ —	Interest expense	$ (1)

As of December 31, 2016, SCE&G expects during the next 12 months to have no reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments 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, 2016			
Interest rate contracts	$ (34)	Interest Expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2016, 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 $2.4 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, 2016	December 31, 2015
in Net Liability Position		
Aggregate fair value of derivatives in net liability position	$ 21.3	$ 47.0
Fair value of collateral already posted	—	3.4
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	21.3	43.6
in Net Asset Position		
Aggregate fair value of derivatives in net asset position	$ 62.0	$ 7.3
Fair value of collateral already posted	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	62.0	7.3

Information related to the offsetting derivative assets follows:

Derivative Assets	Interest Rate Contracts	
Millions of dollars	December 31, 2016	December 31, 2015
Gross Amounts of Recognized Assets	$ 71	$ 15
Gross Amounts Offset in Statement of Financial Position	—	—
Net Amounts Presented in Statement of Financial Position	71	15
Gross Amounts Not Offset - Financial Instruments	(9)	(8)
Gross Amounts Not Offset - Cash Collateral Received	—	—
Net Amount	$ 62	$ 7
Balance sheet location		
Other current assets	—	$ 10
Other deferred debits and other assets	$ 71	5
Total	$ 71	$ 15

Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities Millions of dollars	Interest Rate Contracts December 31, 2016	December 31, 2015
Gross Amounts of Recognized Liabilities	$ 30	$ 55
Gross Amounts Offset in Statement of Financial Position	—	—
Net Amounts Presented in Statement of Financial Position	30	55
Gross Amounts Not Offset - Financial Instruments	(9)	(8)
Gross Amounts Not Offset - Cash Collateral Posted	—	(3)
Net Amount	$ 21	$ 44
Balance sheet location		
Derivative financial instruments	$ 27	$ 33
Other deferred credits and other liabilities	3	22
Total	$ 30	$ 55

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

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:

Millions of dollars	December 31, 2016 Level 2	December 31, 2015 Level 2
Assets:		
Interest rate contracts	$ 71	$ 15
Liabilities:		
Interest rate contracts	$ 30	$ 55

SCE&G had no Level 1 or 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:

Long-Term Debt	December 31, 2016		December 31, 2015	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt	$ 4,919.9	$ 5,489.8	$ 4,516.3	$ 4,851.3

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 fair value, and are based on quoted prices from dealers in the commercial paper market. The resulting fair value is considered to be Level 2.

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.

Millions of dollars	Pension Benefits 2016	Pension Benefits 2015	Other Postretirement Benefits 2016	Other Postretirement Benefits 2015
Benefit obligation, January 1	$ 724.0	$ 773.7	$ 191.2	$ 203.2
Service cost	16.9	19.3	3.6	4.3
Interest cost	33.4	32.2	9.7	9.2
Plan participants' contributions	—	—	1.3	1.9
Actuarial (gain) loss	41.8	(47.0)	11.2	(15.4)
Benefits paid	(47.7)	(54.2)	(8.9)	(10.1)
Amounts funded to parent	—	—	(1.6)	(1.9)
Benefit obligation, December 31	$ 768.4	$ 724.0	$ 206.5	$ 191.2

In 2015, based on an evaluation of the mortality experience of the pension plan, a custom mortality table was adopted for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $18.2 million and $1.9 million, respectively, in 2015.

The accumulated benefit obligation for pension benefits was $742.9 million at the end of 2016 and $702.0 million at the end of 2015.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 2016	Pension Benefits 2015	Other Postretirement Benefits 2016	Other Postretirement Benefits 2015
Annual discount rate used to determine benefit obligation	4.22%	4.68%	4.30%	4.78%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 6.6% 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 2021 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 $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015.

Funded Status

Millions of Dollars December 31,	Pension Benefits 2016	Pension Benefits 2015	Other Postretirement Benefits 2016	Other Postretirement Benefits 2015
Fair value of plan assets	$ 732.9	$ 720.1	—	—
Benefit obligation	768.4	724.0	$ 206.5	$ 191.2
Funded status	$ (35.5)	$ (3.9)	$ (206.5)	$ (191.2)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Current liability	—	—	$ (10.2)	$ (9.6)
Noncurrent liability	$ (35.5)	$ (3.9)	(196.3)	(181.6)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Net actuarial loss	$ 1.9	$ 2.0	$ 1.0	$ 0.7
Prior service cost	—	—	—	—
Total	$ 1.9	$ 2.0	$ 1.0	$ 0.7

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Net actuarial loss	$ 208.8	$ 193.7	$ 28.6	$ 19.9
Prior service cost	2.2	5.2	—	0.2
Total	$ 211.0	$ 198.9	$ 28.6	$ 20.1

In connection with the joint ownership of Summer Station, pension costs attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $23.4 million and $20.3 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $15.8 million and $13.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2016	2015
Fair value of plan assets, January 1	$ 720.1	$ 783.6
Actual return (loss) on plan assets	60.5	(9.3)
Benefits paid	(47.7)	(54.2)
Fair value of plan assets, December 31	$ 732.9	$ 720.1

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, 2016 and 2015 and the target allocation for 2017 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2017**	**2016**	**2015**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	32%
Hedge Funds	9%	11%	11%

For 2017, the expected long-term rate of return on assets will be 7.25%. 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 Va*lue 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, 2016 and 2015, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	2016	2015
Investments with fair value measure at Level 2:		
Mutual funds	$ 115	$ 115
Short-term investment vehicles	15	12
US Treasury securities	17	20
Corporate debt securities	76	72
Municipals	13	13
Total assets in the fair value hierarchy	236	232
Investments at net asset value:		
Common collective trust	$ 418	$ 381
Joint venture interests	79	77
Limited partnership	—	30
Total investments at fair value	$ 733	$ 720

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 2016 or 2015. In addition, in 2015 the fair value of pension plan assets totaling $381 million were previously depicted as mutual funds but have been reclassified as Common collective trust for the current presentation.

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 assets 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
2017	$ 63.1	$ 10.4
2018	65.1	11.0
2019	64.5	11.6
2020	64.7	12.2
2021	67.1	12.8
2022-2026	324.4	69.0

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	2016	2015	2014	2016	2015	2014
Service cost	$ 16.9	$ 19.3	$ 16.0	$ 3.6	$ 4.3	$ 3.6
Interest cost	33.4	32.2	34.1	9.7	9.2	9.2
Expected return on assets	(47.4)	(52.2)	(56.3)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.4	3.5	0.2	0.3	0.3
Amortization of actuarial losses	12.5	11.4	4.0	0.4	1.7	—
Net periodic benefit cost	$ 18.8	$ 14.1	$ 1.3	$ 13.9	$ 15.5	$ 13.1

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 Other Comprehensive Income (OCI), net of tax, were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	—	$ 0.2	$ 0.2	$ 0.3	$ (0.3)	$ 0.4
Amortization of actuarial losses	$ (0.1)	(0.1)	(0.1)	—	—	—
Amortization of prior service cost	—	(0.1)	(0.1)	—	—	—
Total recognized in OCI	$ (0.1)	$ —	$ —	$ 0.3	$ (0.3)	$ 0.4

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

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 26.3	$ 12.2	$ 87.7	$ 9.0	$ (13.7)	$ 15.5
Amortization of actuarial losses	(11.2)	(10.4)	(3.5)	(0.3)	(1.4)	—
Amortization of prior service cost	(3.0)	(3.1)	(2.8)	(0.2)	(0.3)	(0.2)
Total recognized in regulatory assets	$ 12.1	$ (1.3)	$ 81.4	$ 8.5	$ (15.4)	$ 15.3

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2016	**2015**	**2014**	**2016**	**2015**	**2014**
Discount rate	4.68%	4.20%	5.03%	4.78%	4.30%	5.19%
Expected return on plan assets	7.50%	7.50%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%	3.00%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.00%	7.40%
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	2020	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2017 are as follows:

	Pension Benefits	**Other Postretirement Benefits**
Actuarial loss	$ 12.0	$ 1.0
Prior service cost	1.3	—
Total	$ 13.3	$ 1.0

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 the SCE&G totaled $22.9 million in 2016, $21.8 million in 2015 and $20.7 million in 2014. 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 Long-Term Equity Compensation Plan (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 2014-2016 performance cycle provides for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 and 2016-2018 awards are based on performance over a single three-year cycle. In the performance cycle for the 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash and 80% 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. For each of the 2015-2017 and 2016-2018 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. 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 total shareholder return 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. At the Company's discretion, awards under the 2014-2016 performance cycle were paid in cash in February 2017 totaling $20.2 million. Cash-settled liabilities related to earlier performance cycles totaled approximately $13.2 million in 2016, $6.3 million in 2015 and $1.9 million in 2014.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $17.3 million in 2016, $12.2 million in 2015 and $12.6 million in 2014. Such fair value adjustments also resulted in capitalized compensation costs $3.1 million in 2016, $0.6 million in 2015 and $0.6 million in 2014. At December 31, 2016

SCE&G's unrecognized compensation cost, which is expected to be recognized over a weighted -average period of 18 months, was $17.2 million.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under the Price-Anderson Indemnification Act (Price-Anderson), SCE&G (for itself and on behalf of Santee Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the Nuclear Regulatory Commission (NRC) that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at SCE&G's nuclear power plant. 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 $375 million by American Nuclear Insurers 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 currently 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 Summer Station 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 Nuclear Electric Insurance Limited (NEIL). The policies provide coverage to Summer Station 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. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of total coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of 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 $45.8 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with European Mutual Association for Nuclear Insurance (EMANI). The policy provides coverage to Summer Station 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 $1.8 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Summer Station 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.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with a consortium consisting of Westinghouse Electric Company LLC (WEC) and Stone and Webster (Consortium) in 2008 for the design and construction of the New Units. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are 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 New Units. Estimated operating costs, including the depreciation of the utility plant costs, are then to be recovered through rates beginning when the construction of each New Unit is completed and placed into service. The BLRA also provides that, in the event of abandonment prior to plant completion, construction work in progress costs incurred, including AFC, and a return on those costs may be recoverable through rates, so long as SCE&G demonstrates by a preponderance of the evidence that its decision to abandon the New Unit(s) was prudent. As of December 31, 2016, SCE&G's investment in the New Units, including related transmission, totaled $4.5 billion, for which the financing costs on $3.8 billion have been reflected in rates under the BLRA. See Note 2 for a description of rate changes which have occurred under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued Combined Construction and Operating Licenses (COLs) in March 2012. The Consortium has experienced delays throughout much of the project to date, and forecasted work crew efficiency and productivity metrics have not been met. In response, 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. Some of these increased costs were the result of the schedule delays and were the subject of dispute.

October 2015 Amendment and WEC's Engagement of Fluor Corporation (Fluor)

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from Chicago Bridge & Iron Company N.V. (CB&I). Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor as a subcontracted construction manager.

Among other things, the October 2015 Amendment provided SCE&G and Santee Cooper an irrevocable 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, executed the fixed price option, subject to SCPSC approval, on July 1, 2016.

The October 2015 Amendment:

(i) resolved by settlement and release most outstanding disputes between SCE&G and the Consortium,

(ii) revised the contractual guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn IRC Section 45J production tax credits (see also below), resulting in escalating liquidated damages that are capped at an aggregate of $338 million per New Unit (SCE&G's 55% portion being approximately $186 million per New Unit),

(iv) provided for payment to the Consortium of a completion bonus of $150 million per New Unit (SCE&G's 55% portion being approximately $83 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provided for development of a revised construction milestone payment schedule,

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project,

(vii) provided for an explicit definition of Change in Law designed to reduce the likelihood of certain future commercial disputes, with the Consortium also acknowledging and agreeing that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19, and

(viii) eliminated the requirement or ability of any party to bring suit regarding disputes before substantial completion of the project.

As part of its responsibility as a subcontracted construction manager, Fluor has reviewed and assisted in the development of an updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within the SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits (see below). However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to achieve forecasted productivity and work force efficiency levels.

November 2016 SCPSC Order

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. See also Note 2.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at 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 new nuclear construction from 10.5% to 10.25%. This revised ROE will 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 may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. The time period to file a Notice of Appeal of the SCPSC's decision with the South Carolina Supreme Court has expired for three of the four non-settling parties, and none of those parties have filed a Notice of Appeal. As for the remaining non-settling party, the time period for that party to file a Notice of Appeal has not yet expired, but as of April 13, 2017 (the filing date of this FERC Form 1 report), that party has not filed a Notice of Appeal.

Construction Milestone Payment Schedule and Related Dispute Resolution Board (DRB) Activity

The October 2015 Amendment established a DRB process for resolving certain commercial claims and disputes. The DRB is comprised of three members chosen by the parties, and amounts in dispute of less than $5 million will be resolved by the DRB without recourse. Amounts in dispute greater than $5 million will be resolved by the DRB for the remainder of the construction of the New Units, with a reserved right to further arbitrate or to litigate such issues at the conclusion of construction.

On December 2, 2016 the DRB issued an order establishing a construction milestone payment schedule (see (v) in October 2015 Amendment above) on which SCE&G and WEC had been unable to agree subsequent to the October 2015 Amendment. The dispute related only to the timing of payments; the total amount to be paid was not in dispute. The DRB order provides that certain subcontractor and other supplier-related costs incurred by the Consortium will be reimbursed by the owners regardless of payment-milestone completion, but that other payments will be made only upon documented achievement of the agreed-upon payment-milestones. Such subcontractor and other supplier-related costs comprised approximately $873 million of the $3.345 billion of fixed option payments that were the subject of the DRB order.

Payment and Performance Obligations and Certain Related Uncertainties

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba Corporation (Toshiba), parent company of WEC, reaffirmed its guaranty of WEC's payment obligations. Additionally, the EPC Contract provides the owners the right, exercisable upon certain conditions, to obtain payment and performance bonds from WEC equal to 15% of the highest projected three months billings during the applicable year, and their aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bonds.

In late 2015, Toshiba's credit ratings declined to below investment grade following disclosures regarding its operating and financial performance and near-term liquidity. As a result, pursuant to the above-described terms of the EPC Contract, SCE&G has obtained standby letters of credit in lieu of payment and performance bonds from WEC totaling $45 million (or approximately $25 million for SCE&G's 55% share). These standby letters of credit expire annually in February, and they automatically renew for successive one-year periods until their final expiration date of August 31, 2020, unless the issuer provides a minimum 60-day notice that it will not renew. If the issuer provides notice that it will not renew, SCE&G may draw upon the standby letter of credit prior to its expiration. In the event that WEC would be unable to meet its payment and performance obligations under the EPC Contract, it is anticipated this funding would provide a source of liquidity to assist in an orderly transition. In addition, the EPC Contract provides that upon the request of SCE&G, and at owners' cost, the Consortium must escrow certain intellectual property and software for the owners' benefit to assist in completion of the New Units. An escrow arrangement has been established, and certain intellectual property and software have been deposited. Additional deposits are anticipated.

In December 2016 through February 2017, Toshiba and WEC announced further deterioration in their financial position and liquidity related to write-downs arising from WEC's acquisition of Stone and Webster from CB&I (discussed above). The announcements noted that WEC and Toshiba have determined that significant losses will be incurred under the EPC Contract for the New Units and under a similar engineering, procurement and construction agreement for other units currently being constructed in the United States. This determination has impacted their allocation of the CB&I purchase price, resulting in recognition of a large amount of goodwill which has in turn been determined to be impaired. Preliminary recognition of this impairment loss (in excess of $6 billion) has left Toshiba with negative shareholders' equity and threatened its liquidity. In January 2017, Toshiba's credit ratings were further reduced. In response, Toshiba has indicated its interest in monetizing portions of its business as it attempts to restructure and restore its financial position. Toshiba has also indicated that it will withdraw from the nuclear construction business prospectively and that it will significantly alter its risk management oversight of its nuclear power business. WEC has told the SCE&G that it and Toshiba are committed to completing the New Units. Toshiba has acknowledged its parental guaranty to the project, but it has informed the SCE&G that no specific commitment regarding completion of the New Units has been agreed to by it so far.

Toshiba also announced that it had requested (and successfully received) a one-month extension of the deadline for submitting its securities report to Japanese securities regulators for the quarter ended December 31, 2016 to allow an internal investigation into the adequacy of internal controls relating to the purchase price allocation process for WEC's acquisition of Stone & Webster and concerns that senior management at WEC may have exerted inappropriate pressure in order to advance the purchase price allocation process. As part of the announcement, it was stated that Toshiba's audit committee was concerned that an invalidation of internal controls (or even the possibility thereof) might affect Toshiba's quarterly financial statements, and that two law firms had been separately retained by the audit committee and WEC to assist with this investigation.

Although progress on the project was seen in December 2016 and January 2017, including the placement of the first of Unit 2's two steam generators, significant risks and uncertainties remain concerning WEC's ability to improve work force efficiency and productivity performance and to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project. In particular, there can be no assurance that their creditors will continue to provide support or that other sources of liquidity will emerge or continue to be available. In the event that WEC were to fail to complete the project in breach of its obligations under the EPC Contract, its payment obligations for damages would increase substantially above the amount of the liquidated damages described above, but would still be subject to limitations.

On March 29, 2017, WEC filed for Chapter 11 bankruptcy protection with the U.S. Bankruptcy Court for the Southern District of New York. In connection with this filing, SCE&G and Santee Cooper (the V.C. Summer Owners) and WEC and Wectec Global Project Services, Inc., (the Debtors) entered into an Interim Assessment Agreement (the Agreement) which expires on April 28, 2017 unless otherwise terminated as outlined in the Agreement. Under the terms of the Agreement, and while it remains in effect, all parties have agreed to continue to perform under the EPC Contract, to indicate in any press release regarding the New Units that the parties have decided to continue the project, and to give the V. C. Summer Owners the right to discuss project status with Fluor and other subcontractors and vendors and to obtain information and documents from them for the project. The V.C. Summer Owners are obligated to pay all costs accrued by the Debtors for Fluor, other subcontractors and vendors for work performed or services rendered while the Agreement remains in effect.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under possible arrangements with other contractors or, were it determined to be prudent, halting the project and leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA.

Finally, additional claims by the Consortium or SCE&G involving the project schedule, budget and performance may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues, and SCE&G expects to resolve disputes through those means. SCE&G expects to seek recovery through rates of any project costs that arise through such dispute resolution processes, as well as other project costs identified from time to time; however, any such request would be subject to the provisions of the November 2016 SCPSC order discussed above. There can be no assurance that recovery would be granted.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction is subject to customary closing conditions, including receipt of necessary regulatory approvals. This transaction will not affect the payment obligations between the parties during construction of the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. SCE&G’s current projected cost for the additional 5% interest being acquired from Santee Cooper is approximately $850 million.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the IRC to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on current tax law and the contractual guaranteed substantial completion dates (and the recently revised forecasted dates of completion) provided above, both New Units would be operational and would qualify for the nuclear production tax credits; however, any further delays in the schedule or changes in tax law could adversely impact these conclusions. See also the Payment and Performance Obligations and Certain Related Uncertainties discussion above. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan remains under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

SCE&G'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 Clean Air Act, as amended (CAA), Clean Water Act (CWA), Nuclear Waste Act and Comprehensive Environmental Response, Compensation and Liability Act (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 strives to comply with all state and federal regulations regarding those emissions. SCE&G participates in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also has constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce greenhouse gas (GHG) emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the United States Environmental Protection Agency (EPA) issued a revised standard for new power plants by re-proposing New Source Performance Standards under the CAA for emissions of carbon dioxide 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 carbon dioxide per megawatt-hour (MWh) and new natural gas units to meet 1,000 pounds carbon dioxide 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.

In addition, 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 includes state-specific goals for reducing national carbon dioxide emissions by

32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives each state from one to three years to issue State Implementation Plans, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. On February 9, 2016, the United States Supreme Court (Supreme Court) stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G or its generation operations. SCE&G expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. The CSAPR replaces the Clean Air Interstate Rule and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual and ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle National Air Ambient Quality Standard. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide 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 Mercury and Air Toxics Standards (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 National Permit Discharge Elimination System (NPDES) permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The federal effluent limitation guidelines for steam electric generating units (ELG Rule) became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. SCE&G expects that wastewater treatment technology retrofits will be required at Wateree Station. Any costs incurred to comply with the ELG Rule are 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 Coal Combustion Residuals (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 their ash storage ponds and has previously recognized AROs for such ash storage ponds under existing requirements. 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.

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 Summer Station 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 Summer Station 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. SCE&G 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 SCE&G 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 Manufactured Gas Plant (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 the South Carolina Department of Health and Environmental Control and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2018 and will cost an additional $10.2 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, 2016, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $25.7 million and are included in regulatory assets.

Claims and Litigation

SCE&G is subject to various 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.

Operating Lease Commitments

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

	Rent Expense		
Millions of dollars	2016	2015	2014
SCE&G	$ 12.1	$ 12.3	$ 12.0

	Future Minimum Rental Payments					
Millions of dollars	2017	2018	2019	2020	2021	Thereafter
SCE&G	$ 25	$ 23	$ 22	$ 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 SCE&G's regulated utility operations. As of December 31, 2016, SCE&G has recorded AROs of approximately $199 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $310 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	2016	2015
Beginning balance	$ 476	$ 521
Liabilities incurred	—	—
Liabilities settled	(11)	(16)
Accretion expense	21	23
Revisions in estimated cash flows	23	(52)
Ending balance	$ 509	$ 476

Revisions in estimated cash flows in 2016 primarily related to changes in projected costs, based on a nuclear decommissioning cost study. Such revisions in 2015 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. SCE&G's total purchases from this affiliate were $64.5 million in 2016, $94.2 million in 2015 and $120.4 million in 2014. SCE&G's total sales to this affiliate were $64.1 million in 2016, $93.7 million in 2015 and $119.8 million in 2014. The net of the total purchases and total sales are recorded in Other expenses on the consolidated statements of comprehensive income. SCE&G's payable to this affiliate was $4.8 million at December 31, 2016 and insignificant at December 31, 2015. SCE&G's receivable from this affiliate was $4.7 million at December 31, 2016 and insignificant at December 31, 2015.

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy Marketing, Inc. (SCANA Energy) to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $111.5 million in 2016, $128.5 million in 2015 and $195.7 million in 2014. SCE&G's payables to SCANA Energy for such purchases were $8.8 million and $7.5 million as of December 31, 2016 and 2015, respectively.

SCE&G purchases all of the electric generation of A. M. Williams Station, which is owned by GENCO, under a unit power sales agreement. Such unit power purchases, which are included in "Purchased power," totaled approximately $193.9 million and $229.2 million in 2016 and 2015, respectively. SCE&G had approximately $20.2 million and $20.5 million, payable to GENCO for unit power purchases at December 31, 2016 and 2015, respectively.

SCANA Services, Inc. (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 services, and retirement benefits. In addition, SCANA Services processes and pays invoices for SCE&G and is reimbursed. Costs for these services, including amounts capitalized, totaled $331.7 million in 2016, $295.5 million in 2015 and $294.9 million in 2014. Amounts expensed are recorded in Other operation and maintenance - nonconsolidated affiliate and Other expenses on the consolidated statements of comprehensive income. SCE&G's payables to SCANA Services for these services were $62.0 million and $56.3 million at December 31, 2016 and 2015, respectively.

Prior to January 31, 2015, Carolina Gas Transmission Corporation (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 are 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 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 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 non-utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant 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
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	—	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	730	62	—	792
Interest Expense	1	—	$ 209	210
Depreciation and Amortization	281	27	—	308
Segment Assets	9,547	721	3,203	13,471
Expenditures for Assets	925	55	(57)	923
Deferred Tax Assets	4	n/a	(4)	—

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $236 million and $213 million in 2016 and 2015, respectively (net of capitalized interest of $18 million and $14 million in 2016 and 2015, respectively).

Income taxes paid: $286 million and $87 million in 2016 and 2015, respectively.
Income taxes received: $189 million and $84 million in 2016 and 2015, respectively.

Noncash Investing and Financing Activities:

Accrued construction expenditures: $92 million and $225 million in 2016 and 2015, respectively.

Capital leases expenditures: $14 million and $6 million in 2016 and 2015, respectively.

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
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
2015					
Total operating revenues	$ 772	$ 709	$ 806	$ 643	$ 2,930
Operating income	227	208	298	162	895
Earnings Available to Common Shareholder	122	107	164	73	466

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				(3,146,214)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				191,077
3	Preceding Quarter/Year to Date Changes in Fair Value				185,134
4	Total (lines 2 and 3)				376,211
5	Balance of Account 219 at End of Preceding Quarter/Year				(2,770,003)
6	Balance of Account 219 at Beginning of Current Year				(2,770,003)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				169,937
8	Current Quarter/Year to Date Changes in Fair Value				(373,199)
9	Total (lines 7 and 8)				(203,262)
10	Balance of Account 219 at End of Current Quarter/Year				(2,973,265)

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			(3,146,214)	[redacted]	
2			191,077		
3			185,134		
4			376,211	465,780,699	466,156,910
5			(2,770,003)	[redacted]	
6			(2,770,003)		
7			169,937		
8			(373,199)		
9			(203,262)	512,691,483	512,488,221
10			(2,973,265)	[redacted]	

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

Lines 1-5 present information for the period 1/1/15 - 12/31/15.
Lines 6-10 present information for the period 1/1/16 - 12/31/16.

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

Lines 1-5 present information for the period 1/1/15 - 12/31/15.
Lines 6-10 present information for the period 1/1/16 - 12/31/16.

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 2015.

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 2015 (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 2016.

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 2016 (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 2016/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)	10,374,359,941	8,932,065,915
4	Property Under Capital Leases	21,915,190	20,380,905
5	Plant Purchased or Sold		
6	Completed Construction not Classified	380,645,654	339,731,285
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,776,920,785	9,292,178,105
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	4,808,038,309	4,776,576,438
12	Acquisition Adjustments	31,597,076	31,360,826
13	Total Utility Plant (8 thru 12)	15,616,556,170	14,100,115,369
14	Accum Prov for Depr, Amort, & Depl	4,271,191,389	3,671,697,231
15	Net Utility Plant (13 less 14)	11,345,364,781	10,428,418,138
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,061,334,367	3,592,591,410
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	203,247,204	72,609,983
22	Total In Service (18 thru 21)	4,264,581,571	3,665,201,393
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	6,609,818	6,495,838
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,271,191,389	3,671,697,231

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
1,066,246,819				376,047,207	3
62,744				1,471,541	4
					5
39,288,690				1,625,679	6
					7
1,105,598,253				379,144,427	8
					9
					10
18,164,518				13,297,353	11
236,250					12
1,123,999,021				392,441,780	13
416,867,984				182,626,174	14
707,131,037				209,815,606	15
					16
					17
406,126,702				62,616,255	18
					19
					20
10,627,302				120,009,919	21
416,754,004				182,626,174	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
113,980					32
416,867,984				182,626,174	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 2016/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	2,574,132	765,766
3	Nuclear Materials	76,504,565	61,413,516
4	Allowance for Funds Used during Construction	2,082,656	1,522,961
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	81,161,353	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	116,928,535	1,327,653
9	In Reactor (120.3)	223,038,612	685,271
10	SUBTOTAL (Total 8 & 9)	339,967,147	
11	Spent Nuclear Fuel (120.4)	673,993,828	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	786,794,670	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	308,327,658	
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)		

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
	685,271	2,654,627	2
		137,918,081	3
		3,605,617	4
			5
		144,178,325	6
			7
	45,640,963	72,615,225	8
		223,723,883	9
		296,339,108	10
		673,993,828	11
			12
-56,467,219		843,261,889	13
		271,249,372	14
			15
			16
			17
			18
			19
			20
			21
			22

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

True-up invoices relating to Batch 25 transferred from Batch 25 In-Process to Batch 25 Stock.

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

Joint Owner Reimbursement	$44,955,692
Batch 25 True-up transferred to In-Reactor	685,271
Total	$45,640,963

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 2016/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	64,190,621	15,580,615
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	77,414,115	15,580,615
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,569,330	
9	(311) Structures and Improvements	259,790,982	929,469
10	(312) Boiler Plant Equipment	1,071,739,116	16,292,926
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	429,139,375	9,432,370
13	(315) Accessory Electric Equipment	86,860,626	3,099,729
14	(316) Misc. Power Plant Equipment	31,016,219	937,177
15	(317) Asset Retirement Costs for Steam Production	21,400,999	1,835,498
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,913,516,647	32,527,169
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	880,612	
19	(321) Structures and Improvements	281,071,099	24,961,441
20	(322) Reactor Plant Equipment	506,153,128	15,014,581
21	(323) Turbogenerator Units	110,984,878	5,720,699
22	(324) Accessory Electric Equipment	111,928,066	2,873,135
23	(325) Misc. Power Plant Equipment	110,612,254	43,878,232
24	(326) Asset Retirement Costs for Nuclear Production	8,447,945	14,445,881
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,130,077,982	106,893,969
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	29,436,973	5,992
28	(331) Structures and Improvements	49,551,568	226,058
29	(332) Reservoirs, Dams, and Waterways	444,250,322	338,508
30	(333) Water Wheels, Turbines, and Generators	86,389,764	816,819
31	(334) Accessory Electric Equipment	26,371,855	1,018,194
32	(335) Misc. Power PLant Equipment	9,868,315	660,351
33	(336) Roads, Railroads, and Bridges	1,817,517	
34	(337) Asset Retirement Costs for Hydraulic Production	-40,923	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	647,645,391	3,065,922
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,918,325	
38	(341) Structures and Improvements	41,133,097	601,749
39	(342) Fuel Holders, Products, and Accessories	8,181,023	3,383
40	(343) Prime Movers	583,213,249	4,680,171
41	(344) Generators	94,212,708	46,203
42	(345) Accessory Electric Equipment	61,675,001	1,937,297
43	(346) Misc. Power Plant Equipment	1,786,092	215,122
44	(347) Asset Retirement Costs for Other Production	-6,379,626	913,262
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	786,739,869	8,397,187
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,477,979,889	150,884,247

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 2016/Q4

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	83,769,195	1,524,231
49	(352) Structures and Improvements	4,563,204	1,553,709
50	(353) Station Equipment	446,312,291	22,045,819
51	(354) Towers and Fixtures	5,366,642	
52	(355) Poles and Fixtures	358,129,792	31,274,006
53	(356) Overhead Conductors and Devices	210,657,538	9,426,336
54	(357) Underground Conduit	20,724,924	1,199,319
55	(358) Underground Conductors and Devices	62,616,065	-1,180,726
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)	1,192,213,418	65,842,694
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	53,677,693	3,205,028
61	(361) Structures and Improvements	4,910,716	
62	(362) Station Equipment	375,387,762	19,992,443
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	435,508,406	27,348,513
65	(365) Overhead Conductors and Devices	478,007,884	18,322,720
66	(366) Underground Conduit	145,349,698	5,352,509
67	(367) Underground Conductors and Devices	430,986,100	20,165,637
68	(368) Line Transformers	453,720,392	17,455,783
69	(369) Services	275,169,193	8,707,818
70	(370) Meters	100,522,891	12,027,342
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	294,849,774	21,507,425
74	(374) Asset Retirement Costs for Distribution Plant	160,586	60,470
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,048,251,095	154,145,688
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	8,695,915	
87	(390) Structures and Improvements	147,896,423	-243,056
88	(391) Office Furniture and Equipment	11,232,030	3,078,582
89	(392) Transportation Equipment	19,417,920	321,674
90	(393) Stores Equipment	270,242	
91	(394) Tools, Shop and Garage Equipment	3,809,290	82,171
92	(395) Laboratory Equipment	6,277,458	345,104
93	(396) Power Operated Equipment	51,065,026	11,676,392
94	(397) Communication Equipment	7,392,058	323,977
95	(398) Miscellaneous Equipment	5,996,162	559,763
96	SUBTOTAL (Enter Total of lines 86 thru 95)	262,052,524	16,144,607
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	-1,858	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	262,050,666	16,144,607
100	TOTAL (Accounts 101 and 106)	9,057,909,183	402,597,851
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)	9,057,909,183	402,597,851

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 2016/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
430,611		81,456	79,422,081		4
430,611		81,456	92,645,575		5
					6
					7
8,679			13,560,651		8
2,248,268		-29,091	258,443,092		9
40,043,711		-485,485	1,047,502,846		10
					11
2,211,241		382,988	436,743,492		12
990,683			88,969,672		13
875,788		7,555	31,085,163		14
25,725,227			-2,488,730		15
72,103,597		-124,033	1,873,816,186		16
					17
			880,612		18
50,967			305,981,573		19
4,989,647		-1,651,792	514,526,270		20
1,250,589			115,454,988		21
205,661			114,595,540		22
274,840		1,651,792	155,867,438		23
			22,893,826		24
6,771,704			1,230,200,247		25
					26
3,915		-274	29,438,776		27
52,951			49,724,675		28
349,943			444,238,887		29
238,265			86,968,318		30
3,057,064			24,332,985		31
74,897			10,453,769		32
			1,817,517		33
-40,921		2			34
3,736,114		-272	646,974,927		35
					36
			2,918,325		37
9,402		7,706	41,733,150		38
774,583			7,409,823		39
7,017,441		13,754	580,889,733		40
698,736			93,560,175		41
22,369			63,589,929		42
43,589			1,957,625		43
-125,847			-5,340,517		44
8,440,273		21,460	786,718,243		45
91,051,688		-102,845	4,537,709,603		46

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
		-1,037,100	84,256,326		48
		-16,621	6,100,292		49
616,222		-741,863	467,000,025		50
10,582			5,356,060		51
1,328,741		-128,090	387,946,967		52
1,193,895		128,090	219,018,069		53
1,379,428			20,544,815		54
4,202,425			57,232,914		55
			73,767		56
					57
8,731,293		-1,795,584	1,247,529,235		58
					59
		1,037,100	57,919,821		60
9,688			4,901,028		61
1,978,832		775,027	394,176,400		62
					63
4,454,738			458,402,181		64
2,599,204			493,731,400		65
300,113			150,402,094		66
4,931,073			446,220,664		67
3,338,343			467,837,832		68
197,838			283,679,173		69
543,238			112,006,995		70
					71
					72
2,617,785			313,739,414		73
			221,056		74
20,970,852		1,812,127	3,183,238,058		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
11,553		-308,606	8,375,756		86
388,193		-38,285,400	108,979,774		87
596,697			13,713,915		88
1,313,800			18,425,794		89
22,419			247,823		90
79,206			3,812,255		91
295,334			6,327,228		92
5,292,262			57,449,156		93
287,586		-16,544	7,411,905		94
243,897			6,312,028		95
8,530,947		-38,610,550	231,055,634		96
					97
-1,857		1			98
8,529,090		-38,610,549	231,055,634		99
129,713,534		-38,615,395	9,292,178,105		100
					101
					102
					103
129,713,534		-38,615,395	9,292,178,105		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 2016/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					
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43					
44					
45					
46					
47	TOTAL				

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

Dominion Carolina Gas Transmission LLC (DCGT) rented office space in a facility that is owned by SCE&G and classified as electric utility plant on the Company's books. DCGT's lease of this facility was terminated as of July 2016. In addition, DCGT rented a field operations building that is owned by SCE&G and was classified as common utility plant on the Company's books at the time. DCGT's lease of this facility was also terminated as of July 2016.

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 2016/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				
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11				
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15				
16				
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21	Other Property:			
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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 2016/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	Wateree Waste Water Pond	3,949,494
3	Cope Catalyst	1,223,766
4	Wateree Limestone Ball Mill	1,027,946
5	Wateree Mist Eliminator System	811,095
6	Cope Dual Fuel Firing Systems	752,396
7	Wateree #1 480v MCC & C.H. 4160v	601,311
8	McMeekin #2 Exciter Voltage Regulator	366,141
9	McMeekin #1 Gas Ignitors	365,023
10	Cope 'D' Coal Mill Gearbox	337,629
11	Wateree Spare ESS Transformer	334,748
12	Urquhart #3 4160v Breakers	289,543
13	Urquhart Wastewater System	204,725
14	Minor Steam Production	1,656,271
15	Nuclear Production	
16	VCS #2 & #3 Work Order	4,208,534,114
17	VCS #1 Head Replacement	46,458,145
18	VCS #1 RBCU Industrial Coolers	11,862,166
19	VCS #1 Fukushima Response Strategy	4,790,060
20	VCS #1 Bravo Chiller Replacement	4,499,124
21	VCS #1 Chemical Treatment Equipment	3,730,379
22	VCS #1 SIEM Project	3,680,756
23	VCS #1 Alternate FW Suction Source	3,323,679
24	VCS #1 System Flow Control - CIPP	3,059,553
25	VCS #1 Open Phase Detection System	2,358,646
26	VCS #1 EFW Flow Control Venturi	1,841,342
27	VCS #1 Waste Water Treatment Outfall 005	1,830,595
28	VCS #1 B Loop Aux Crane Replacement	1,491,173
29	VCS #1 Simplex Equipment Replacement	1,391,740
30	VCS #1 License Renewal Project	1,362,187
31	VCS #1 S/R Charlie Chiller Replacement	1,313,302
32	VCS #1 S/R PORV Controls	1,097,081
33	VCS #1 Replace RMWST Heat Tracing	1,054,425
34	VCS #1 Site Drainage Security - Additional	1,038,966
35	VCS #1 PORV Tailpipe Equalizing Line	682,700
36	VCS #1 Waste Water Treatment Outfall 001	545,177
37	VCS #1 DG Exhaust Manifold Replacement	528,625
38	VCS #1 Alpha FWP Turbine Blade Replacement	425,772
39	VCS #1 New Plant Support Building	398,144
40	VCS #1 Control Bldg KWh Meter Replacement	346,566
41	VCS #1 Penstock Piping Project	327,519
42	VCS #1 Additional Protected Area Grounding	280,148
43	TOTAL	4,776,576,438

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 2016/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 RCCA Tool	203,714
2	Minor Nuclear Production	1,432,511
3	Hydro Production	
4	Saluda Motor Control Ctr & Power Ctr	1,272,034
5	Fairfield Pump 480V MCC & 13.8kV Switchgear	306,288
6	Minor Hydro Production	236,341
7	Other Production	
8	Minor Other Production	360,690
9	Overhead Transmission Lines	
10	Yemassee-Burton 230/115kV	13,671,312
11	Cainhoy 230kV: Foldin #2, Reterm #1	3,799,995
12	Thomas Isl.-Jack Primus 115kV R/W	3,728,121
13	Cain-MP#1:Rebld SPDC & Retap Hamlin	2,045,610
14	AMW - Mt Pleasant #2 Line - Reterm.	1,576,781
15	Toolebeck Transmission 115kV	1,226,498
16	Lyles - Williams Street 115kV Line	1,057,751
17	Faber Place - Hagood 115kV Line #2	732,563
18	#0270B:Thomas Is.-Jack Primus115	672,697
19	McMeekin-Michelin 115kV: Rplc Arrest	593,499
20	Blythewood 115kV Fold In	583,552
21	Williams-Faber Place Replace Strs	510,791
22	NY Wire 115kV Tap-Replace Switches	453,263
23	Burton-St. Hel. Island 115kV G-Line	383,457
24	Queensboro SW Station - Terminate Lines	356,527
25	Summerville-Pepperhill 230kV Line	317,413
26	Yem-McIntosh 115kV: Thermal Uprate	315,707
27	Victory Gardens-Circle Dr. 115kV	265,750
28	AMW-Cainhoy:Rebld SPDC B795	257,837
29	Saluda Hydro Harbison 115 Reterm to LM	236,650
30	Cainhoy-Mt. Pleasant: Install OPGW	224,565
31	Minor Overhead Transmission Lines	750,236
32	Overhead Transmission Lines NND	
33	VCS2-St. George 230kV Line #1 & #2	26,407,944
34	VCS2-LMT 230kV Line #2	24,486,475
35	VCS1-Killian(Winn-Blythwd) 230kV(C)	19,578,429
36	VCS2-St. George 230kV Line #2	18,554,151
37	VCS2-St. George 230kV Line #1 & #2	17,572,801
38	St George-Summerville #1 230kV BLRA	16,681,049
39	Canadys-Sumter 230kV	13,551,823
40	VCS2-St. George 230kV Line #1 & #2	12,064,090
41	VCS1-Killian(Blywd-Killian)230kV(C)	11,845,138
42	VCS1-Killian(WinnJct-Winn)230kV(C)	11,724,656
43	TOTAL	4,776,576,438

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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	VCS2-St. George 230kV Line #1 & #2	8,362,206
2	Saluda River-Lyles 230kV BLRA	7,518,682
3	VCS2-St. George 230kV Line #1	6,247,828
4	Denny Terrace-Lyles 230kV	5,262,650
5	Proj 94Q:Saluda Hydro-Newberry 115kV	4,261,765
6	VCS1-Killian 230kV Line: R/W (C)	4,012,716
7	VCS2-St. George 230kV Line #1 & #2	3,246,642
8	VCS2-LMT 230kV Line #1	3,096,108
9	Project #0090N4 Reterm Denny Terrace	2,827,782
10	VCS2-St. George 230kV Line #2	2,359,235
11	VCS1-DT (VCS1-Winn Jct) 230kV	2,144,494
12	VCS2-St. George 230kV Line #1 & #2	1,937,418
13	Parr-Winn 115 #1 Reloc Parr-Switch	1,251,117
14	VCS2-St. George 230kV Line #1 & #2	1,063,392
15	Project 0090M1:Reterm Duke Newport	1,039,732
16	VCS1-Killian(VCS1-WinnJct) 230kV(C)	1,030,935
17	Project #0090N2 Reterm Ward 230kV	951,218
18	McMeekin-Lake Murray Trans. 115kV	873,203
19	Project #0091F: Parr-Midway DC 115	836,049
20	Parr-Denny Terrace 115kV #14 Line	766,230
21	Saluda Hydro-LMT 115 kV	661,877
22	Project #0090N3: Reterm Duke (BR)	491,056
23	Project #0090N6 Temp Energize VCS#2	205,422
24	Overhead Transmission Lines Non BLRA	
25	Dunbar Rd-Orangeburg 115kV	9,364,162
26	St George-Summerville 230kV Line #2	7,982,799
27	VCS-St. George 230kV Line #1	6,756,105
28	VCS2-St.George 1 & 2 Add ROW	1,382,669
29	VCS2-St. George 230kV #1	1,312,736
30	Dunbar Rd.-Orangeburg 115kV	672,267
31	Minor Overhead Transmission Lines Non BLRA	89,631
32	Transmission Substation	
33	Cainhoy 230-115kV Trans. Sub - Cons	9,727,088
34	Blythewood 115kV Sw St - Construct	4,916,097
35	Toolebeck Sw. Station: Construct	4,832,636
36	Summerville Transmission Sub #2071	4,242,784
37	Urquhart Add Switch House	3,536,843
38	Ward - 2nd Autobank & Bus Tie Bkrs	2,844,104
39	Okatie 115kV Sw Station - Construct	2,440,378
40	O'burg East Sub:2 230kV Terms	2,318,568
41	Batesburg Trans. Sub: Add Transfmr	1,675,379
42	Queensboro Transmission Sub #2057	1,437,010
43	TOTAL	4,776,576,438

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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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	Burton Substation - Add 115kV Term.	1,296,079
2	AM Williams Station #2541	854,528
3	Wateree Station 230kV Sub #2531	697,260
4	Saluda Hyd Sub: Ugd 115 Term to SRT	484,000
5	Non-CIP FRAD Replacement	413,162
6	Calhoun County Sub-Relocate SCADA Poles	279,871
7	Denny Terrace Fence Upgrade	246,727
8	CIPv5: 2015 Low Impact Northern Division	225,062
9	Minor Transmission Substation	2,607,647
10	Transmission Substation NND	
11	Saluda River 230/115kV: Construct	12,762,179
12	St. George 230kV Sw Station - Construct	7,428,591
13	Saluda River 230/115kV Sub Site	3,355,688
14	Various 115kV PRCB's: Upgrade	837,434
15	Saluda Hydro Sub: Upgrade 115kV Bus	611,566
16	Various Subs-Upgrd 115kV Bkrs	499,939
17	Killian-Add 1 230kV Terminal-VCS 1	491,498
18	Lake Murray Trans: Add 230kV Term	443,636
19	Parr Steam - Reterminate DT #14	371,767
20	Denny Terrace 230kV Sub. #2045	349,595
21	St.George 230/115kV Sub-Purchase Land	334,044
22	Lyles 230kV Substation #2202	277,778
23	Minor Transmission Substation NND	824,438
24	Distribution Substation	
25	Jack Primus 115-23kV Sub: Construction	1,904,677
26	Sewee Sub.No. 807- Construct	1,044,447
27	Sweetwater 115-12kV Sub: Incr. Capacity	1,015,973
28	Ridgeville 115-46kV - Inst. 22.4MVA	797,605
29	Denmark Ind Pk Sub: Add Transformer	467,422
30	ACS RTU Replacement - 2015	410,706
31	Replac T3111 Bluffton 115-23kV, 28M	378,627
32	Purch Spare 115-23kV, 10.5MVA Transformer	359,373
33	Olar 46-4kv: Convert to 12kV.	268,423
34	Minor Distribution Substation	744,732
35	Customer Substation	
36	Clemson W.T. Sub: Construct 115/23	818,877
37	Minor Customer Substation	127,711
38	Overhead Distribution Lines	
39	Gills Creek Conversion Phase V	353,828
40	Ckt Inspec 2015 Sub 479/CKT 60282	214,302
41	Minor Overhead Distribution Lines	1,366,421
42	UG Distribution Lines	
43	TOTAL	4,776,576,438

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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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	Chas Eastside Station Rebuild	1,672,241
2	The Hotel at Marion Square - UG Service	276,504
3	Pine Hill Sub Exit Feeders 1 & 2	275,752
4	Minor UG Distribution Lines	2,360,399
5	Land and Structures	
6	Install System Prot Training Facility	1,056,972
7	174 King St. Renovations-Charleston	229,926
8	Minor Land and Structures	37,457
9	Transportation & POE	
10	Minor Transportation & POE	217,410
11	Office Furniture and Equipment	
12	Minor Office Furniture and Equipment	66,993
13	Communication Equipment	
14	Replace Entire Radio System	526,594
15	Minor Communication Equipment	11,544
16	Tools & Test Equipment	
17	Admin WO AFUDC Adjustments	-2,352,610
18	Minor Tools & Test Equipment	201,442
19	Intangible Plant	
20	VCS - NFPA 805 Software	16,209,740
21	CHAMPS Replacement	5,277,318
22	Seismic PRA Project	8,080,791
23	Configuration Mgmt. Software	2,257,685
24	Work Management System	1,232,101
25	Cope DCS Software	1,226,625
26	Cope Simulator Software	497,319
27	OSI PI Software	467,542
28	MRule & ER Software	412,600
29	Vegetation Management	301,581
30	AVERT Software	210,667
31	Underground Piping Program	204,594
32	Minor Intangible Plant	485,689
33	Transmission - BLRA-VCS1	
34	VC Summer Sub #2561 - Upgrade PrCB's	8,793,756
35	VCS#1-Upgd 2 Terms & Repl Disc Switch	4,273,687
36	VCS#1-Add Term & Repl 2 Disc Switch	3,844,146
37	VCS1 Upgr 230kV 8902 & 8932	3,344,394
38	VCS1, Bus1: SCPSA Upg 8852 Add 9322	2,973,305
39	Parr Safeguard 115kV	2,699,154
40	VCS1 Add Pineland Terminal fr VCS1	2,195,512
41	VCS1 Upgrade Terminal 8832	1,264,253
42	Project #0090H: VCS #2 Tie to VCS #1	1,093,032
43	TOTAL	4,776,576,438

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	Parr 115kV Safeguard - Raise @ VCS	851,870
2	Project #0090J: VCS #2 to VCS #1 Bus #3	762,519
3	VCS3 Tie to VCS1 Bus #1: Bus Tie #1	674,802
4	VCS1, Bus 1: SCPSA repl 8863 & LA's	461,794
5	Payroll Overheads and Adjustments	-256,169
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43	TOTAL	4,776,576,438

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 2016/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 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	3,507,257,793	3,507,257,793		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	222,528,059	222,528,059		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,491,910	3,491,910		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-379,741	-379,741		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	225,640,228	225,640,228		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	126,265,283	126,265,283		
13	Cost of Removal	27,736,544	27,736,544		
14	Salvage (Credit)	2,627,228	2,627,228		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	151,374,599	151,374,599		
16	Other Debit or Cr. Items (Describe, details in footnote):	11,067,988	11,067,988		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,592,591,410	3,592,591,410		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	807,546,643	807,546,643		
21	Nuclear Production	595,592,811	595,592,811		
22	Hydraulic Production-Conventional	302,503,203	302,503,203		
23	Hydraulic Production-Pumped Storage	74,272,616	74,272,616		
24	Other Production	397,855,840	397,855,840		
25	Transmission	347,879,446	347,879,446		
26	Distribution	975,383,660	975,383,660		
27	Regional Transmission and Market Operation				
28	General	91,557,191	91,557,191		
29	TOTAL (Enter Total of lines 20 thru 28)	3,592,591,410	3,592,591,410		

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)	$129,713,534
Less: Intangible Plant per Page 205, Line 5 column (d)	(430,611)
Capital Lease Asset Reductions Recorded in Accordance with USoA General Instruction No. 20 shown as Plant Retirements	(3,017,640)
Total	$126,265,283

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

ARC retirements reclassified to Regulatory Assets	$ 19,328,763
Gain on Disposal on Vehicles	(154,195)
Book Cost of Land Retired	24,147
Transfers and Adjustments	(8,130,727)
Total	$ 11,067,988

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 2016/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			659,092
3	Louisa Refined Coal, LLC			276,263
4	Brandon Shores Coaltech, LLC			459,003
5	Brunner Island Refined Coal, LLC			
6	Cope Refined Coal, LLC			
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21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	1,394,608

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
-1,356,690		718,021		2
-1,367,246		244,529		3
-1,371,246		265,597		4
		1,627,983		5
			1,398,039	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-4,095,182		2,856,380	1,398,039	42

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

Amount includes additional investments made during the year of $1,550,574. Also in 2016 $134,955 of assets of Canadys Refined Coal, LLC was distributed to SCE&G and these assets were contributed to Brunner Island Refined Coal, LLC as part of SCE&G's initial investment.

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

Amount includes additional investments made during the year of $1,335,512.

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

Amount includes additional investments made during the year of $1,177,840.

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

Amount is comprised of investments made during the year of $1,493,028. Also in 2016 $134,955 of assets of Canadys Refined Coal, LLC was distributed to SCE&G and these assets were contributed to Brunner Island Refined Coal, LLC as part of SCE&G's initial investment.

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 2016 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 2016/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)	57,600,683	46,289,912	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)	92,694,189	96,230,379	Electric
8	Transmission Plant (Estimated)	8,078,742	8,440,866	Electric
9	Distribution Plant (Estimated)	26,809,680	29,483,037	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	447,255	367,869	Fleet
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	128,029,866	134,522,151	
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)	351		
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	185,630,900	180,812,063	

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 2016/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)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	211,290.20	649,339	45,625.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	569.00		27,845.00	
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	4,294.80	8,759		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	207,564.40	640,580	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)	659.50	56		
45	Gains	659.50	56		
46	Losses				

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.

2018		2019		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
45,625.00		45,625.00		1,186,250.00		1,534,415.20	649,339	1
								2
								3
27,845.00				45,625.00		101,884.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						4,294.80	8,759	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
73,470.00		45,625.00		1,231,875.00		1,632,004.40	640,580	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
				659.50	18	1,319.00	74	44
				659.50	18	1,319.00	74	45
								46

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

Vintage 2017 allowances allocated by the EPA for the CSAPR SO2 Group 2 program.

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

Vintage 2018 allowances allocated by the EPA for the CSAPR SO2 Group 2 program.

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

Vintage 2046 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 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.

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 2016/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)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	40,331.80	6,804		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	120.20		8,817.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	GENCO- Associated Company	495.00			
10					
11					
12					
13					
14					
15	Total	495.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	26,819.30	6,804		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	14,127.70		8,817.00	
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				
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 2016/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.

2018 No. (f)	2018 Amt. (g)	2019 No. (h)	2019 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
						40,331.80	6,804	1
								2
								3
8,817.00						17,754.20		4
								5
								6
								7
								8
						495.00		9
								10
								11
								12
								13
								14
						495.00		15
								16
								17
						26,819.30	6,804	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
8,817.00						31,761.70		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 4 Column: b

Vintage 2016 New Unit Set Aside Allowances allocated by the EPA for the CSAPR Nox Ozone Season program.

Schedule Page: 229 Line No.: 4 Column: d

Vintage 2017 New Unit Set Aside allowances allocated by the EPA for the CSAPR Nox Annual program.

Schedule Page: 229 Line No.: 4 Column: f

Vintage 2018 allowances allocated by the EPA for the CSAPR Nox Annual program.

Schedule Page: 229 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 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.

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 2016/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						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	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 2016/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs 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	13,331,507
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.	141,056,111	4,755,494	407	12,270,624	103,221,687
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	1,005,199			1,427,729
47						
48						
49	TOTAL	162,803,474	5,760,693		13,878,217	118,538,678

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 2016/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	Rainbow Energy -				
3	System Impact Study	5,071	408.1/561.6/926	15,000	253
4					
5	Rainbow Energy -				
6	System Impact Study	3,908	408.1/561.6/926	15,000	253
7					
8	Rainbow Energy -				
9	Facilities Study	333	408.1/561.6/926	3,600	253
10					
11	Santee Cooper Longpoint -				
12	Facilities Study	139	408.1/561.6/926		
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23	20151013004 System Impact Study	3,127	408.1/561.7/926		
24	20151216001 System Impact Study	5,033	408.1/561.7/926	40,000	253
25	20160208001 Facilities Study	1,482	408.1/561.7/926	35,600	253
26	20160810001 Facilities Study			32,500	253
27	20160810001 System Impact Study	3,034	408.1/561.7/926	50,000	253
28	20150612001 Facilities Study	2,871	408.1/561.7/926		
29	20150608003 Facilities Study	1,257	408.1/561.7/926		
30	20160805001 Supplemental Review	1,021	408.1/561.7/926	1,800	253
31	20151105001 System Impact Study	1,523	408.1/561.7/926		
32	20151028002 Facilities Study	373	408.1/561.7/926	3,000	253
33	20151028002 System Impact Study	1,496	408.1/561.7/926		
34	20160328001 Facilities Study	359	408.1/561.7/926		
35	20160328001 System Impact Study	2,226	408.1/561.7/926	11,000	253
36	20151210001 Feasibility Study	2,056	408.1/561.7/926	1,000	253
37	20160811001 System Impact Study	1,429	408.1/561.7/926	20,000	253
38	20150928001 System Impact Study	1,496	408.1/561.7/926		
39	20150812001 Facilities Study	165	408.1/561.7/926		
40	20150812002 System Impact Study	1,005	408.1/561.7/926		

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	20150812003 Facilities Study	1,082	408.1/561.7/926		
23	20150812002 Facilities Study	980	408.1/561.7/926		
24	20150918001 Facilities Study	747	408.1/561.7/926	4,700	253
25	20151223001 System Impact Study	1,786	408.1/561.7/926	2,800	253
26	20151014001 System Impact Study	902	408.1/561.7/926	2,000	253
27	20151028001 Facilities Study	1,667	408.1/561.7/926	100,000	253
28	20151028001 System Impact Study	5,396	408.1/561.7/926		
29	20150623001 System Impact Study	4,036	408.1/561.7/926		
30	20151105002 System Impact Study	1,056	408.1/561.7/926		
31	20151125001 System Impact Study	1,124	408.1/561.7/926	2,800	253
32	20160212001 System Impact Study	1,912	408.1/561.7/926	4,500	253
33	20150623001 Facilities Study	1,884	408.1/561.7/926	100,000	253
34	20151125001 Facilities Study	887	408.1/561.7/926	3,500	253
35	20151013003 System Impact Study	2,364	408.1/561.7/926		
36	20150706002 Facilities Study	1,874	408.1/561.7/926		
37	20150730002 Facilities Study	1,309	408.1/561.7/926		
38	20150730001 Facilities Study	902	408.1/561.7/926		
39	20151124001 System Impact Study	1,087	408.1/561.7/926		
40	20151124002 System Impact Study	902	408.1/561.7/926		

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	20150615001 Facilities Study	2,369	408.1/561.7/926		
23	20150608002 Facilities Study	688	408.1/561.7/926		
24	20150831001 Facilities Study	1,715	408.1/561.7/926		
25	20151013002 Facilities Study	1,495	408.1/561.7/926		
26	20151013003 Facilities Study	1,184	408.1/561.7/926		
27	20151013001 Facilities Study	975	408.1/561.7/926		
28	20151124001 Facilities Study	1,011	408.1/561.7/926	4,500	253
29	20151124002 Facilities Study	1,301	408.1/561.7/926	3,000	253
30	20160927001 System Impact Study	234	408.1/561.7/926	20,200	253
31	20161027002 System Impact Study			13,600	253
32	20161027002 Facilities Study			15,010	253
33	20151112001 System Impact Study	1,493	408.1/561.7/926	2,800	253
34	20151230001 System Impact Study	1,709	408.1/561.7/926	2,000	253
35	20151230002 System Impact Study	1,417	408.1/561.7/926	2,000	253
36	20151106002 Facilities Study	469	408.1/561.7/926	4,500	253
37	20160105001 Facilities Study	2,464	408.1/561.7/926	17,200	253
38	20160725001 Supplemental Review			2,100	253
39	20151106002 System Impact Study	915	408.1/561.7/926		
40	20150608002 Facilities Study	625	408.1/561.7/926	22,800	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					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20161006001 System Impact Study			26,271	253
23	20160805002 Supplemental Review	1,021	408.1/561.7/926	1,800	253
24	20150423001 Facilities Study	2,382	408.1/561.7/926		
25	20160803001 System Impact Study	2,520	408.1/561.7/926	82,500	253
26	20160721001 Supplemental Review	2,100	408.1/561.7/926	3,750	253
27	20150629001 Facilities Study	109	408.1/561.7/926		
28	20150930001 System Impact Study	601	408.1/561.7/926		
29	20150706001 Facilities Study	4,073	408.1/561.7/926		
30	20150713001 Facilities Study	51	408.1/561.7/926	5,250	253
31	20151106003 System Impact Study	1,281	408.1/561.7/926	1,800	253
32	20160707001 Facilities Study	513	408.1/561.7/926	10,482	253
33	20150623002 Facilities Study	60	408.1/561.7/926		
34					
35					
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39					
40					

Schedule Page: 231 Line No.: 3 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.

Schedule Page: 231 Line No.: 6 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.

Schedule Page: 231 Line No.: 9 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.

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 2016/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	275,729,600	25,938,400	282	8,612,800	293,055,200
2	Columbia & Charleston Franchise	21,669,711		407	4,183,224	17,486,487
3	Gas Water Heater Rebate Program (2011-2021)	4,598,419	2,542,896	912	1,842,125	5,299,190
4	Decommissioning Asset Ret. Obligation	51,793,945	23,050,165	Various	25,609,115	49,234,995
5	MGP Environmental Remediation	34,815,047	94,092,471	735	103,210,753	25,696,765
6	Deferred ARO Accretion & Depreciation Costs	318,225,828	34,827,349	Various	14,315,880	338,737,297
7	Interest Rate Derivatives	525,958,158	253,590,943	244/427	168,108,545	611,440,556
8	Deferred Employee Benefit Plan Costs-Gas (ASC 715)	29,595,698	30,181,441	Various	29,690,306	30,086,833
9	Deferred Employee Benefit Plan Costs-Elec (ASC 715)	190,915,766	212,400,407	Various	191,639,510	211,676,663
10	Gas Customer Awareness Program (11/2011-10/2018)	548,681	603	913	335,707	213,577
11	Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	4,873,967		530	183,816	4,690,151
12	Deferred Capacity Charges (7/2010-7/2020)	1,344,334		555	296,000	1,048,334
13	Deferred Capacity Charges	2,097,311	37,200			2,134,511
14	Electric Demand Side Management	66,102,359	19,435,179	254/908	21,173,780	64,363,758
15	Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	8,226,259		555	282,660	7,943,599
16	Economic Development Grants (10/2009-11/2031)	5,393,311	10,376,170	921	1,033,738	14,735,743
17	Major Maintenance Accrual and Interest	5,636,230	14,562,139	Various	9,049,480	11,148,889
18	Deferred Pension Cost - Gas (11/2013-1/2027)	11,396,113		926	1,029,508	10,366,605
19	Deferred Pension Cost - Electric (1/2013-12/2042)	56,689,427		926	1,987,835	54,701,592
20	Environmental Compliance Studies (7/2010 - 7/2020)	430,472		506	94,782	335,690
21	Deferred Pollution Control Costs -					
22	Wateree (1/2013-9/2040)	26,217,896		407.3	1,061,940	25,155,956
23	Research and Development Grant (1/2013-12/2047)	3,200,000		930.2	100,000	3,100,000
24	Environmental Remediation Cost	365,099	3,056,173	Various	3,292,485	128,787
25	Amount Undercollected - Gas Cost Adjustment	7,019,370	70,542,815	Various	63,310,161	14,252,024
26	Gas WNA Cap - Winter 2015 (11/2016 - 10/2021)	1,194,644	968,520	480/481	72,105	2,091,059
27	Gas WNA Cap - Winter 2016		914,938			914,938
28	Fukushima Compliance Costs	3,665,646	1,662,106	Various	1,234,222	4,093,530
29	Undercollected Electric Pension Expense	5,997,929	14,959,319	926	19,598,798	1,358,450
30	Deferred Long-Term Capacity Contract	8,730,837	17,000,883	555/565	10,800,000	14,931,720
31	Carrying Costs Accrual	18,232,429	13,970,853			32,203,282
32	Cyber Compliance Costs	994,388	2,748,822			3,743,210
33	CIPv5 Compliance Costs	2,367,253	4,568,249			6,935,502
34	Gas Pipeline Integrity Costs	3,723,778	4,114,293	887	1,881,142	5,956,929
35	DER and NET Metering Costs	731,511	3,143,274	Various	4,901,025	-1,026,240
36	Coal Supply Contract Termination (5/2015-12/2016)	1,200,000		501	1,200,000	
37	Nuclear Refueling Outage Costs	3,903,725		524/528	3,903,725	
38	Deferred Costs Related to Certain Claims					
39	for Tax Deductions and Credits		15,337,175			15,337,175
40	Deferred Storm Damage Costs		19,706,491			19,706,491
41						
42						
43						
44	TOTAL	1,703,585,141	893,729,274		694,035,167	1,903,279,248

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.

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. 2013-50-E, 2013-208-E, 2014-44-E, 2015-45-E and 2016-40-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.: 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. 2016-6-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, 2016 are as follows:

Commodity	$ 4,630,213
Demand	9,621,811
Total	$14,252,024

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

SCPSC Docket No. 2016-6-G

Schedule Page: 232 Line No.: 28 Column: a

SCPSC Docket No. 2012-277-E

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

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2014-88-E
SCPSC Docket No. 2016-103-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.: 30 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.: 31 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.

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

SCPSC Docket No. 2015-372-E

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

SCPSC Docket No. 2014-416-E

Schedule Page: 232 Line No.: 34 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.: 35 Column: a

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

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

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

SCPSC Docket No. 2012-218-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 2016/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	34,101,368	27,973,631	Various	22,859,427	39,215,572
3	Charleston Garage Revenue Bond					
4	Long-Term	1,612,061	47,752	143	1,249,500	410,313
5	5 year Commitment Fees	5,369,844	1,817	427	1,371,781	3,999,880
6	3 Year Commitment Fees	294,529		427	153,667	140,862
7	Progress Payments/Plant Equipmt	4,694,777	16,980,975	Various	13,868,006	7,807,746
8	Director's Endowment	382,447	24,466	426.5	27,389	379,524
9	Pole Attachment Receivables	2,193,680	4,498,537	143/589	4,506,585	2,185,632
10	Long Term Power Plant Service					
11	Agreement (2007-2021)	1,311,576	16,724,672	107/553	16,613,718	1,422,530
12	Lease Buyout Costs (2009-2057)	5,273,501		Various	194,249	5,079,252
13	Department of Energy Nuclear					
14	Loan Guarantee Application					
15	Fee	1,183,076				1,183,076
16	Workers' Comp Reserve	397,772	4,635	925	25,779	376,628
17	NND Transmission Lines	90,000		107	90,000	
18	Multi-year Cloud Computing					
19	Fees (2014-2017)	130,030		912	104,024	26,006
20	McMeekin Solar Study	116,552		923	116,552	
21	Income Tax Receivable -					
22	Amended Returns		72,124,423			72,124,423
23	Other	-6,983	30,188,579	Various	30,761,374	-579,778
24						
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47	Misc. Work in Progress	27,490,688				31,470,149
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	84,634,918				165,241,815

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

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

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 2016/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	Regulatory Asset - Asset Retirement Obligation	140,717,394	143,551,826
3	Other Post Employment Benefits	58,815,900	62,870,700
4	Unamortized Investment Tax Credits	13,633,600	12,841,000
5	Storm Damage	1,492,000	-7,537,800
6	Nuclear Refueling Costs	-1,493,100	4,466,400
7	Other	8,463,300	8,166,500
8	TOTAL Electric (Enter Total of lines 2 thru 7)	221,629,094	224,358,626
9	Gas		
10	Regulatory Asset - Asset Retirement Obligation	7,950,100	10,247,700
11	Other Post Employment Benefits	8,664,800	9,155,000
12	Environmental Remediation	-6,383,900	-6,195,000
13	Incentive Compensation	4,134,000	4,131,300
14	Unamortized Investment Tax Credits	973,000	903,300
15	Other	2,450,700	2,148,200
16	TOTAL Gas (Enter Total of lines 10 thru 15	17,788,700	20,390,500
17	Other (Specify): Non Operating	36,607,402	44,397,878
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	276,025,196	289,147,004

Notes

Line 7 "Other":

	Balance at Beg. of Year	Balance at End of Year
Major Maintenance	(2,155,800)	(4,267,700)
Early Retirement Programs	3,492,800	2,904,400
Reserve for Injuries and Damages	1,924,800	2,655,000
Nuclear Fuel	(1,307,100)	2,411,500
Vacation Accrual	1,909,400	1,701,300
Uncollectible Accounts	929,300	1,069,500
Incentive Compensation	888,500	894,500
Long Term Disability	308,100	256,800
Regulatory Asset/Liability, Interest Rate Derivatives	1,984,900	-
All Other	488,400	541,200
Total	$ 8,463,300	$ 8,166,500

Line 15 "Other":

	Balance at Beg. of Year	Balance at End of Year
Inventory Capitalization under 236A	$ 611,600	$ 563,800
Early Retirement Programs	628,100	470,600
Reserve for Injuries and Damages	123,400	351,300
Vacation Accrual	337,700	301,100
Uncollectible Accounts	204,500	169,700
Long Term Disability	353,000	99,400
All Other	192,400	192,300
Total	$ 2,450,700	$ 2,148,200

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 2016/Q4

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.

Line 17 "Other":

	Balance at Beg. of Year	Balance at End of Year
Regulatory Asset - Asset Retirement Obligation	$33,488,202	$41,058,978
Directors' Endowment	1,195,800	1,244,900
Early Retirement Programs	876,400	840,200
Other Post Employee Benefits	428,100	621,300
All Other	618,900	632,500
Total	$36,607,402	$44,397,878

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 2016/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 2016/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

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

Schedule Page: 253.1 Line No.: 7 Column: b

During 2016, the Company received equity advances from SCANA in the amount of $100,000,000. The entry was:

Account	Debit	Credit
131 - Cash	$100,000,000	
208 - Donations Received from Stockholders		$100,000,000

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 2016/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		
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22	TOTAL	4,335,379

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	4.50% Series due 2064 (State Commission Order Nos. 2010-660 issued on 03-30-2010		
10	and 2013-277 Issued on 05-09-2013)	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	5,029,541,381	52,302,580

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	4.35% Series, due 2042	250,000,000	2,559,709
5			-21,570,000 P
6			
7	6.50% Series, due 2018	300,000,000	2,214,194
8			861,000 D
9			
10	6.05% Series, due 2038	175,000,000	1,916,924
11			728,000 D
12			
13	5.50% Series, due 2039	150,000,000	1,517,157
14			1,179,000 D
15			
16	3.22% Series, due 2021	30,000,000	329,625
17			
18	5.45% Series, due 2041	250,000,000	2,187,500
19			917,500 D
20			
21	5.45% Series, due 2041	100,000,000	1,361,577
22			-2,799,000 P
23			
24	4.60% Series, due 2043	400,000,000	4,234,911
25			2,000,000 D
26			
27	5.10% Series, due 2065	500,000,000	5,325,812
28			4,035,000 D
29			
30	4.10% Series, due 2046 (State Commission Order No. 2013-277 Issued on 05-09-2013)	425,000,000	3,718,750
31			875,500 D
32			
33	TOTAL	5,029,541,381	52,302,580

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 2016/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	Pollution Control Facilities Revenue Bonds:		
3	4% Industrial Revenue, due 2028	39,480,000	426,014
4			-2,694,115 P
5			
6	3.625% Industrial Revenue, due 2033	14,735,000	158,164
7			258,157 D
8			
9	Variable Industrial Revenue, due 2038	35,000,000	492,221
10			
11	Amortization of Interest Rate Derivative Contracts:		
12	6.625% $300 Million due 2/1/2032		
13	5.80% $200 Million due 1/15/2033		
14	6.25% $125 Million due 7/1/2036		
15	5.30% $300 Million due 5/21/2033		
16	5.25% $250 Million due 11/1/2018		
17	5.25% $100 Million due 3/1/2035		
18	6.05% $250 Million due 1/15/2038		
19	6.05% $110 Million due 1/15/2038		
20	6.05% $175 Million due 1/15/2038		
21	5.50% $150 Million due 12/15/2039		
22	5.45% $250 Million due 2/1/2041		
23	5.45% $100 Million due 2/1/2041		
24	4.35% $250 Million due 2/01/2042		
25	4.35% $250 Million due 2/01/2042		
26	4.60% $75 Million due 6/14/2043		
27	4.60% $75 Million due 6/14/2043		
28	4.60% $90 Million due 6/14/2043		
29	4.60% $80 Million due 6/14/2043		
30	4.60% $80 Million due 6/14/2043		
31	$35 Million SIFMA due 11/30/2038		
32	4.50% $300 Million due 06/01/2064		
33	TOTAL	5,029,541,381	52,302,580

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% $75 Million due 06/01/2064		
2	5.10% $500 Million due 06/01/2065		
3	4.10% $425 Million due 06/15/2046		
4	SUBTOTAL - Account 221	4,929,215,000	49,476,097
5			
6	Account 224 - Other Long Term Debt:		
7	Variable Rate Lines of Credit		
8	Contract on Natural Gas Distribution system		
9	Acquired from Charleston AFB	424,844	
10	Commitment Fees		
11	Nuclear Fuel Contract	99,901,537	2,826,483 D
12	SUBTOTAL - Account 224	100,326,381	2,826,483
13			
14			
15			
16			
17			
18			
19			
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32			
33	TOTAL	5,029,541,381	52,302,580

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 2016/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	1,856,250	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
				4,929,035,579	253,679,997	33

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
07-13-2012	02-01-2042	07-13-2012	02-01-2042	250,000,000	10,875,000	4
						5
						6
10-02-2008	11-01-2018	10-02-2008	11-01-2018	300,000,000	19,500,000	7
						8
						9
03-17-2009	01-15-2038	03-17-2009	01-15-2038	175,000,000	10,681,275	10
						11
						12
12-09-2009	12-15-2039	12-09-2009	12-15-2039	150,000,000	8,250,000	13
						14
						15
10-18-2011	10-18-2021	10-18-2011	10-18-2021	30,000,000	966,000	16
						17
01-27-2011	02-01-2041	01-27-2011	02-01-2041	250,000,000	13,625,000	18
						19
						20
05-24-2011	02-01-2041	05-24-2011	02-01-2041	100,000,000	5,450,000	21
						22
						23
06-14-2013	06-15-2043	06-14-2013	06-15-2043	400,000,000	18,400,000	24
						25
						26
06-01-2015	06-01-2065	06-01-2015	06-01-2065	500,000,000	25,500,000	27
						28
						29
06-13-2016	06-15-2046	06-13-2016	06-15-2046	425,000,000	9,535,347	30
						31
						32
				4,929,035,579	253,679,997	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
01-15-2013	02-01-2028	01-15-2013	02-01-2028	39,480,000	1,579,200	3
						4
						5
01-15-2013	02-01-2033	01-15-2013	02-01-2033	14,735,000	534,144	6
						7
						8
12-01-2008	12-01-2038	12-01-2008	12-01-2038	34,555,000	1,015,902	9
						10
						11
		01-31-2002	02-01-2032		-32,251	12
		01-23-2003	01-15-2033		-5,185	13
		06-27-2006	07-01-2036		-194,951	14
		05-21-2003	05-15-2033		321,412	15
		11-06-2003	11-01-2018		302,671	16
		03-08-2005	03-01-2035		46,107	17
		01-14-2008	01-15-2038		263,307	18
		06-24-2008	01-15-2038		-10,073	19
		03-17-2009	01-15-2038		363,375	20
		12-09-2009	12-15-2039		-423,481	21
		01-27-2011	02-01-2041		289,740	22
		05-24-2011	02-01-2041		207,282	23
		01-30-2012	02-01-2042		-256,278	24
		07-13-2012	02-01-2042		-25,471	25
		06-14-2013	06-15-2043		282,178	26
		06-14-2013	06-15-2043		283,034	27
		06-14-2013	06-15-2043		-324,505	28
		06-14-2013	06-15-2043		-290,385	29
		06-14-2013	06-15-2043		-282,868	30
		12-01-2013	11-30-2038		-132,248	31
		06-01-2014	06-01-2064		163,206	32
				4,929,035,579	253,679,997	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.
		06-13-2016	06-01-2064		36,717	1
		06-01-2015	06-01-2065		311,720	2
		06-13-2016	06-15-2046		765,827	3
				4,928,770,000	249,050,723	4
						5
						6
						7
						8
				265,579	12,690	9
					3,176,424	10
03-01-2013	11-01-2016	03-01-2013	11-01-2016		1,440,160	11
				265,579	4,629,274	12
						13
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						19
						20
						21
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						23
						24
						25
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						29
						30
						31
						32
				4,929,035,579	253,679,997	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.: 7 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.: 9 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 12/31/2016, the outstanding amount related to this obligation was $265,579.

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

SCANA Holding Company (parent of SCE&G) allocates interest expense on commitment fees to its operating subsidiaries. During 2016, the portion allocated to SCE&G was $289,738.

Schedule Page: 256.3 Line No.: 11 Column: a

In February 2013, SCE&G entered into a contract to acquire Enriched Uranium Product (EUP) for the initial core load of the V.C. Summer Nuclear Station Unit No. 3 currently under construction. Under the provisions of the contract, SCE&G recorded $99.9 million within Account 224 - Other Long-Term Debt and $2.8 million within Account 226 - Unamortized Discount on Long-Term Debt. Payment to satisfy the obligation was made in November 2016.

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

The interest expense of $6,296,983 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 12/31/2016, 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 2016/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)	512,691,483
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized	214,487,780
6	Pension Plan	1,380,543
7	Recovery of Deferred Capacity	296,000
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Total Net Book Income Tax (Including Investment Tax Credit)	240,215,857
11	Book Depreciation and Amortization	269,797,518
12	Book Expense - Nuclear Fuel	56,467,219
13	Other (see detail)	71,930,913
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	44,134,820
16	Regulatory Asset - Carrying Costs	13,970,852
17	Regulatory Asset Deferred Capacity	6,238,082
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	1,224,241,496
21	Repair Allowance Deduction	46,745,212
22	Domestic Production Activities Deduction	44,793,992
23	Contributions in Aid of Construction	17,563,142
24	Storm Damage Costs	23,607,306
25	Cybersecurity	7,317,071
26	Other (see detail)	15,481,010
27	Federal Tax Net Income	-76,825,670
28	Show Computation of Tax:	
29	Tax @ 35%	-26,888,985
30		
31	Adjustments for Prior Years	-117,517,970
32	Other (see detail)	-11,235,480
33	Current Federal Income Tax Expense Recorded	-155,642,435
34		
35		
36		
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44		

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

Deferred Fuel Costs	$24,322,080
Deferred Nuclear Fuel Expenses	15,580,797
Regulatory Asset - Unrecovered Plant	9,135,210
Other Post Retirement Benefits	3,620,647
Nuclear Decommissioning Expense Accrual	3,210,606
Injuries and Damages	2,504,442
Book Vehicle Depreciation Charged to Operations	2,503,377
Section 162m limitation	2,501,376
Net Metering	1,757,750
Pollution Control	1,344,598
Coal Supply Contract Termination	1,200,000
Amortization of Losses on Reacquired Debt	1,142,386
Environmental Remediation Costs	798,991
Meals and Lobbying	710,000
Demand Side Management	519,610
Regulatory Asset - Customer Programs	335,103
Uncollectible Accounts	275,701
VCS Costs	183,816
Directors' Endowment	157,028
All Other	127,395
Total	$71,930,913

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

Major Maintenance Programs	$ 5,521,170
State Income Tax Deduction	(2,398,715)
Gas Pipeline Integrity	2,233,149
Early Retirement Programs	1,834,068
Gas WNA Cap	1,811,353
Regulatory Asset - Interest/Professional Fees	1,682,475
Prepayment Acceleration	1,217,757
Regulatory Asset - McMeekin	1,005,199
Long Term Disability	797,117
Accrued Vacation	592,163
Fukushima Compliance	427,884
All Other	757,390
Total	$15,481,010

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

Partnership Credits	($ 8,252,167)
Regulatory Asset - Sec 41/Sec 199	(2,983,313)
Total	($11,235,480)

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 2016 by each member of the consolidated group were as follows:

SCANA Corporation	($ 21,613,000)
SCANA Communications Holding, Inc.	410,284
SCANA Services	5,064,100
South Carolina Electric & Gas Company	(158,874,935)*
South Carolina Fuel Company	3,232,500 *
South Carolina Generating Company	1,526,840
Public Service of North Carolina	(15,947,900)
PSNC Blue Ridge Corporation	507,200
PSNC Clean Energy Enterprises, Inc.	(400)
PSNC Cardinal Pipeline Corporation	1,156,100
SCANA Energy Marketing, Inc.	15,814,300
Servicecare, Inc.	(401,900)
Total	($169,126,811)

* ($155,642,435)

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 2016/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	133,512,837		-155,642,435	70,530,962	92,660,560
3	FUTA	4,421		240,882	236,836	-3,222
4	FICA	755,937		32,954,030	32,419,211	-456,945
5	Other Miscellaneous		18,975	36,300	36,318	
6	SUBTOTAL	134,273,195	18,975	-122,411,223	103,223,327	92,200,393
7						
8	State:					
9	Income	30,260,353		-18,521,476	28,580,507	16,841,630
10	License			15,558,278	15,558,278	
11	Vehicle License			195,754	195,754	
12	Electric Generation	446,156		7,318,334	7,294,250	
13	SUTA	7,217		528,686	519,719	-6,676
14	Other Miscellaneous					
15	SUBTOTAL	30,713,726		5,079,576	52,148,508	16,834,954
16						
17	Local:					
18	County Property	163,330,465	608,528	180,188,699	164,695,505	
19	Municipal Property	9,051,422		9,412,475	8,588,175	
20	SUBTOTAL	172,381,887	608,528	189,601,174	173,283,680	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
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39						
40						
41	TOTAL	337,368,808	627,503	72,269,527	328,655,515	109,035,347

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 2016/Q4

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
		-144,978,100			-10,664,335	2
5,245		90,848			150,034	3
833,811		12,887,390			20,066,640	4
	18,993				36,300	5
839,056	18,993	-131,999,862			9,588,639	6
						7
						8
		-18,767,040			245,564	9
		13,743,589			1,814,689	10
					195,754	11
470,240		7,318,334				12
9,508		188,281			340,405	13
						14
479,748		2,483,164			2,596,412	15
						16
						17
178,828,708	613,577	158,134,174			22,054,525	18
9,875,722		8,274,507			1,137,968	19
188,704,430	613,577	166,408,681			23,192,493	20
						21
						22
						23
						24
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						39
						40
190,023,234	632,570	36,891,983			35,377,544	41

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

Reclassified amount to account 186 - Misc Deferred Debits	$70,282,000
Reclassified amount to account 282 - Accumulated Deferred Income Taxes	(25,859,800)
Overpayment of taxes reclassified to account 143 - Other Accounts Receivable	40,728,060
Reclassified amount to account 182 - Regulatory Asset	7,510,300
Total	$92,660,560

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

Estimated payroll taxes in the amount of ($3,131,055) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2016. Those adjustments are combined with a total of $2,664,212 of payroll taxes related to at-risk incentive compensation actually paid in 2016 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($466,843).

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

Estimated payroll taxes in the amount of ($3,131,055) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2016. Those adjustments are combined with a total of $2,664,212 of payroll taxes related to at-risk incentive compensation actually paid in 2016 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($466,843).

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

Overpayment of taxes reclassified to account 143 - Other Accounts Receivable	$20,843,530
Reclassified amount to account 282 - Accumulated Deferred Income Taxes	(4,001,900)
Total	$16,841,630

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

Estimated payroll taxes in the amount of ($3,131,055) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2016. Those adjustments are combined with a total of $2,664,212 of payroll taxes related to at-risk incentive compensation actually paid in 2016 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($466,843).

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 2016/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%	232,112			411.4	40,500	
4	7%						
5	10%	16,354,646			411.4	910,800	
6	8%	5,374,268			411.4	324,100	
7	20%	48,674			411.4	4,200	
8	TOTAL	22,009,700				1,279,600	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	25,534			411.4	5,100	
13	10%	644,815			411.4	52,400	
14	20%	13,292			411.4	900	
15	8%	887,159			411.4	54,200	
16	Total Gas	1,570,800				112,600	
17							
18							
19							
20							
21							
22							
23							
24							
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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
191,612	58.4 Years		3
			4
15,443,846	58.4 Years		5
5,050,168	58.4 Years		6
44,474	58.4 Years		7
20,730,100			8
			9
			10
			11
20,434	47.5 Years		12
592,415	47.5 Years		13
12,392	47.5 Years		14
832,959	47.5 Years		15
1,458,200			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
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			47
			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 2016/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	10,706,259	Various	2,966,654	1,132,586	8,872,191
4	Accrued Liability - Incentive Plan	4,466,531	Various	38,852,042	39,018,888	4,633,377
5	Gas Environmental Remediation	18,544,499	182.3	101,694,928	93,373,262	10,222,833
6	Other Environmental Remediation	609,200	Various	23,063,400	23,065,776	611,576
7	Long-Term Disability	1,728,353	131	2,111,652	1,314,535	931,236
8	Accrued Liability - Director's					
9	Endowment Program	3,126,294	131	78,374	206,858	3,254,778
10	Life Insurance Premium Obligation	5,996	926	6,057	3,118	3,057
11	Santee River Basin Accord	1,145,905	131	135,308	35,528	1,046,125
12	Municipal Nonstandard Service Fund					
13	Matching Obligation	5,007,710	186	18,910,124	19,647,565	5,745,151
14	SRS Substation	1,901,603	456	96,283		1,805,320
15	Interconnection Study Deposits	535,451	234/456	1,489,471	1,271,864	317,844
16	New Nuclear Transmission Lines	90,000	131	90,000		
17	CIAC Obligations	17,914,870	107/118	3,876,283	3,197,321	17,235,908
18	Noncontrolling Interest - SCFC	2,696,226				2,696,226
19	FIN 48 Interest		431	411,700	2,770,500	2,358,800
20	Other	776,926	Various	2,831,803	3,005,634	950,757
21						
22						
23						
24						
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41						
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46						
47	TOTAL	69,255,823		196,614,079	188,043,435	60,685,179

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 2016/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	12,361,300		322,000
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	12,361,300		322,000
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)	12,361,300		322,000
18	Classification of TOTAL			
19	Federal Income Tax	10,745,400		279,900
20	State Income Tax	1,615,900		42,100
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 2016/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		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)	Balance at End of Year (k)	Line No.
							1
							2
							3
						12,039,300	4
							5
							6
							7
						12,039,300	8
							9
							10
							11
							12
							13
							14
							15
							16
						12,039,300	17
							18
						10,465,500	19
						1,573,800	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 2016/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	1,370,839,208	578,229,200	174,717,185
3	Gas	153,285,200	18,954,100	3,097,200
4	Other - Non Operating	8,810,700		
5	TOTAL (Enter Total of lines 2 thru 4)	1,532,935,108	597,183,300	177,814,385
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,532,935,108	597,183,300	177,814,385
10	Classification of TOTAL			
11	Federal Income Tax	1,364,350,091	526,334,600	156,919,200
12	State Income Tax	168,585,017	70,848,700	20,895,185
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 2016/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		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)	Balance at End of Year (k)	Line No.
							1
		182.3	2,397,593	182.3/236.0	54,520,900	1,826,474,530	2
		182.3	681,800	182.3	1,279,200	169,739,500	3
3,700	1,360,900					7,453,500	4
3,700	1,360,900		3,079,393		55,800,100	2,003,667,530	5
							6
							7
							8
3,700	1,360,900		3,079,393		55,800,100	2,003,667,530	9
							10
3,000	1,183,600		2,707,951		48,520,600	1,778,397,540	11
700	177,300		371,442		7,279,500	225,269,990	12
							13

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 2016/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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Asset - ARO	115,255,100	7,730,900	316,000
4	Employee Benefit Plan Costs	73,025,300	11,023,400	3,082,400
5	Unrecovered Plant Canadys	49,246,400		4,669,600
6	Prepayments	24,830,600	953,300	
7	Demand Side Management Costs	22,951,600	383,400	526,300
8	All Other	-9,574,800	27,861,800	39,053,900
9	TOTAL Electric (Total of lines 3 thru 8)	275,734,200	47,952,800	47,648,200
10	Gas			
11	Employee Benefit Plan Costs	11,320,400	668,300	480,500
12	Regulatory Asset - ARO	6,466,500	430,500	
13	Deferred Fuel Costs	2,684,900	8,450,700	5,684,200
14	Prepayments	4,135,600		485,900
15	Gas Pipeline Integrity	1,424,300	854,300	
16	All Other	-317,900	1,701,400	621,100
17	TOTAL Gas (Total of lines 11 thru 16)	25,713,800	12,105,200	7,271,700
18	Non Operating	63,769,800		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	365,217,800	60,058,000	54,919,900
20	Classification of TOTAL			
21	Federal Income Tax	317,476,600	52,207,300	47,764,800
22	State Income Tax	47,741,200	7,850,700	7,155,100
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 2016/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					
		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)	Balance at End of Year (k)	Line No.
							1
							2
						122,670,000	3
						80,966,300	4
						44,576,800	5
						25,783,900	6
						22,808,700	7
				182.3	4,653,500	-16,113,400	8
					4,653,500	280,692,300	9
							10
						11,508,200	11
						6,897,000	12
						5,451,400	13
						3,649,700	14
						2,278,600	15
						762,400	16
						30,547,300	17
5,633,100	6,482,300			219	80,400	63,001,000	18
5,633,100	6,482,300				4,733,900	374,240,600	19
							20
4,896,700	5,634,500				4,115,100	325,296,400	21
736,400	847,800				618,800	48,944,200	22
							23

NOTES (Continued)

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
Deferred Fuel Costs	($10,139,300)	$15,862,200	$27,930,700		($22,207,800)
Pension Plan	(14,705,600)	3,001,000	8,515,800		(20,220,400)
Regulatory Asset- Deferred Capacity	4,145,300	2,386,100	-		6,531,400
Reacquired Debt	5,532,400	97,600	436,900		5,193,100
FAS109 - Sec 174	-	-	-	$4,653,500	4,653,500
Cyber Security	-	4,084,600	-		4,084,600
VCS Costs	1,864,300	-	70,300		1,794,000
Fukushima Compliance	1,412,400	163,700	10,300		1,565,800
Grants	841,500	153,000	-		994,500
Regulatory Asset- Professional Fees	-	643,700	-		643,700
Recovery of Deferred Capacity	514,200	-	116,700		397,500
All Other	960,000	1,469,900	1,973,200		456,700
Total	($ 9,574,800)	$27,861,800	$39,053,900	$4,653,500	($16,113,400)

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

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Balance at End of Year
Gas WNA Cap		$ 1,149,800		$ 1,149,800
Pension Plan	($1,207,100)	551,600	$ 402,400	(1,057,900)
Reacquired Debt	676,500	-	87,600	588,900
Regulatory Asset- Customer Programs	212,700	-	131,100	81,600
Total	($ 317,900)	$ 1,701,400	$ 621,100	$ 762,400

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
Pension Plan	$50,297,100	$ -	$ 46,300	$ 80,400	$50,331,200
Regulatory Asset- Carrying Costs	6,974,000	5,343,900	200		12,317,700
FIN48 Interest	423,000	281,700	332,900		371,800
Partnership Credits	6,075,700	7,500	6,102,900		(19,700)
Total	$63,769,800	$ 5,633,100	$ 6,482,300	$ 80,400	$63,001,000

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 2016/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	14,606,600	190	862,300		13,744,300
2	Storm Damage Reserve	3,900,815	571/593	3,900,815		
3	Nuclear Refueling Accrual		524/528	11,405,361	23,082,433	11,677,072
4	NOX Emission Allowance Proceeds	153,865	447	153,295	463	1,033
5	Interest Rate Derivatives (3/2009-6/2043)	96,111,382	176/427/421	16,609,739	71,128,530	150,630,173
6	Demand Side Management Carrying Costs	5,952,053	182.3	1,781,297	562,055	4,732,811
7	SO2 Emission Allowance Proceeds	871			86	957
8	Wholesale Fuel Overcollection	1,077,834	447	859,879	1,649,389	1,867,344
9	Amt. Overcollected - Elec Fuel Adjustment Clause	25,431,776	449/173	151,121,526	181,882,008	56,192,258
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	147,235,196		186,694,212	278,304,964	238,845,948

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

SCPSC Docket No. 95-1000-E
SCPSC Docket No. 2007-335-E
SCPSC Docket No. 2008-416-E
SCPSC Docket No. 2009-489-E
SCPSC Docket NO. 2012-218-E

Schedule Page: 278 Line No.: 3 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 278 Line No.: 5 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.

Schedule Page: 278 Line No.: 6 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

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

SCPSC Docket No. 2016-2-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 2016/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	1,184,394,884	1,144,628,202
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	850,736,352	829,184,845
5	Large (or Ind.) (See Instr. 4)	433,854,479	427,958,743
6	(444) Public Street and Highway Lighting	14,775,119	14,364,720
7	(445) Other Sales to Public Authorities	47,755,097	47,280,395
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,531,515,931	2,463,416,905
11	(447) Sales for Resale	45,568,557	49,093,118
12	TOTAL Sales of Electricity	2,577,084,488	2,512,510,023
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,577,084,488	2,512,510,023
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,778,151	7,199,589
17	(451) Miscellaneous Service Revenues	4,156,675	3,698,815
18	(453) Sales of Water and Water Power	385,910	431,911
19	(454) Rent from Electric Property	19,530,616	20,040,653
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	3,598,591	5,165,454
22	(456.1) Revenues from Transmission of Electricity of Others	7,839,445	8,058,377
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	42,289,388	44,594,799
27	TOTAL Electric Operating Revenues	2,619,373,876	2,557,104,822

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 2016/Q4

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
8,139,813	7,977,834	605,717	596,686	2
				3
7,518,727	7,398,918	94,375	93,178	4
6,264,991	6,201,242	783	757	5
74,895	73,740	1,025	1,022	6
525,787	520,849	3,125	3,191	7
				8
				9
22,524,213	22,172,583	705,025	694,834	10
946,981	942,262	4	4	11
23,471,194	23,114,845	705,029	694,838	12
				13
23,471,194	23,114,845	705,029	694,838	14

Line 12, column (b) includes $ 91,773,090 of unbilled revenues.

Line 12, column (d) includes 721,010 MWH relating to unbilled revenues

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

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.: 5 Column: e

Includes 3,267 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 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: c

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

Residential	($31,953,022)
Commercial	(30,007,949)
Industrial	(25,682,833)
Street Lighting	(309,214)
Other Public Authorities	(2,133,595)
	($90,086,613)

Includes Unmetered Sales Revenue as follows:

Residential	$19,257,846
Commercial/Industrial	29,633,344
Street Lighting	13,520,908
Other Public Authorities	145,036
	$62,557,134

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

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: e

Includes Unmetered MWH Sales as follows:

Residential	80,027
Commercial/Industrial	148,709
Street Lighting	66,053
Other Public Authorities	1,038
	295,827

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

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.: 10 Column: g

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	209,733
Commercial/Industrial	24,858
Street Lighting	972
Other Public Authorities	59
	235,622

Schedule Page: 300 Line No.: 17 Column: b

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.: 17 Column: c

Includes $1,317,527 of reconnect and lighting disconnect charges.

Includes $2,254,755 of transmission maintenance fee revenue.

Includes $450,753 of returned check fees.

Account balance also includes debit activity of ($487,963) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 21 Column: b

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.

Schedule Page: 300 Line No.: 21 Column: c

Includes $4,362,458 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $401,419 of rental 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 2016/Q4

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					
15					
16					
17					
18					
19					
20					
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				

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 2016/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	332,590	46,266,484	21,316	15,603	0.1391
3	2	24,059	4,359,475	15,241	1,579	0.1812
4	5	1,061	151,758	69	15,377	0.1430
5	6	477,597	66,529,604	31,243	15,287	0.1393
6	7	292	36,526	10	29,200	0.1251
7	8	7,209,348	1,046,196,194	536,356	13,441	0.1451
8	E1N	671	96,650	70	9,586	0.1440
9	E2N	4	1,090	5	800	0.2725
10	E5N	9	1,218	1	9,000	0.1353
11	E6N	789	115,554	98	8,051	0.1465
12	E8N	8,106	1,232,979	1,048	7,735	0.1521
13	M1N	339	47,138	20	16,950	0.1391
14	M2N	2	464	2	1,000	0.2320
15	M5N	4	627	1	4,000	0.1568
16	M6N	549	76,779	40	13,725	0.1399
17	M8N	2,635	382,949	197	13,376	0.1453
18	Special (A)	81,759	18,899,395	210,488	388	0.2312
19	Total Residential	8,139,814	1,184,394,884	816,205	9,973	0.1455
20						
21	Commerical & Industrial Sales					
22	by Rate					
23	3	16,681	1,935,394	349	47,797	0.1160
24	9	2,669,981	362,478,075	79,092	33,758	0.1358
25	10	4,802	914,501	2,216	2,167	0.1904
26	11	15,969	1,647,545	318	50,217	0.1032
27	12	164,992	18,860,172	3,697	44,629	0.1143
28	14	21,705	3,174,728	1,851	11,726	0.1463
29	16	44,966	5,944,826	2,836	15,855	0.1322
30	20	1,900,899	200,604,151	2,156	881,679	0.1055
31	21	365,407	35,342,078	548	666,801	0.0967
32	22	419,750	50,327,991	1,740	241,236	0.1199
33	23	4,107,370	306,714,995	122	33,666,967	0.0747
34	24	2,037,082	172,968,599	181	11,254,597	0.0849
35	27	926,085	60,414,812	10	92,608,500	0.0652
36	28	2,422	301,128	20	121,100	0.1243
37	60	934,875	34,337,599	3	311,625,000	0.0367
38	E9N	1,058	140,042	20	52,900	0.1324
39	Special (A)	149,675	28,484,195	24,390	6,137	0.1903
40	Total Commercial & Industrial	13,783,719	1,284,590,831	119,549	115,298	0.0932
41	TOTAL Billed	21,803,203	2,439,742,841	0	0	0.1119
42	Total Unbilled Rev.(See Instr. 6)	721,010	91,773,090	0	0	0.1273
43	TOTAL	22,524,213	2,531,515,931	0	0	0.1124

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 2016/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	1,448	188,776	99	14,626	0.1304
4	9	2,361	451,418	545	4,332	0.1912
5	13	3,812	498,126	382	9,979	0.1307
6	Special (A)	67,272	13,636,799	1,059	63,524	0.2027
7	Total Public Street & Hwy Lights	74,893	14,775,119	2,085	35,920	0.1973
8						
9	Other Sales to Public Authorities					
10	by Rate					
11	3	145,519	16,830,073	2,917	49,887	0.1157
12	9	1,440	214,404	145	9,931	0.1489
13	20	12,600	1,187,557	7	1,800,000	0.0943
14	21	3,222	293,560	3	1,074,000	0.0911
15	65	70,801	5,432,159	21	3,371,476	0.0767
16	66	291,931	23,757,298	32	9,122,844	0.0814
17	Special (A)	274	40,046	10	27,400	0.1462
18	Total OPAs	525,787	47,755,097	3,135	167,715	0.0908
19						
20						
21						
22						
23						
24						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	21,803,203	2,439,742,841	0	0	0.1119
42	Total Unbilled Rev.(See Instr. 6)	721,010	91,773,090	0	0	0.1273
43	TOTAL	22,524,213	2,531,515,931	0	0	0.1124

Schedule Page: 304 Line No.: 19 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)

Schedule Page: 304 Line No.: 40 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)

Schedule Page: 304.1 Line No.: 7 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)

Schedule Page: 304.1 Line No.: 18 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)

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 2016/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		3.5	3.7	3.7
2	City of Orangeburg	RQ		136.0	146.4	142.5
3	Town of Winnsboro	RQ		12.0	11.7	11.5
4	Cargill Power Markets, LLC	OS				
5	Duke Energy Carolinas, LLC	OS				
6	Morgan Stanley Capital Group, Inc.	OS				
7	The Energy Authority, Inc.	OS				
8	Emissions Allow Sales - Revenue Contra					
9	Wholesale Fuel Over/Under Collection					
10						
11						
12	Transmission Revenue included in					
13	Energy Charges Column (i).					
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
20,600	539,753	611,149		1,150,902	1
843,444	11,940,202	28,862,323		40,802,525	2
64,165	1,209,125	2,180,926	146,892	3,536,943	3
16,747		622,646		622,646	4
1,700		74,650		74,650	5
200		8,400		8,400	6
125		5,625		5,625	7
			-476	-476	8
			-632,658	-632,658	9
					10
					11
					12
					13
					14
928,209	13,689,080	31,654,398	146,892	45,490,370	
18,772	0	711,321	-633,134	78,187	
946,981	**13,689,080**	**32,365,719**	**-486,242**	**45,568,557**	

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 Tariff, Seventh Revised Volume No. 2 for the time period 1/1/2016 through 5/31/2016. Winnsboro PSA for the time period 6/1/2016 - 12/31/2016.

Schedule Page: 310 Line No.: 3 Column: j

Network transmission and ancillary services charges for the Town of Winnsboro. The transmission reservation that was held by SCE&G Power Marketing as agent for the Town of Winnsboro terminated on 05/31/2016. Transmission base revenue totals $129,212 and ancillary services revenue totals $17,680 through 05/2016.

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: 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.: 6 Column: c

FERC Electric tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 7 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.: 7 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 8 Column: j

Transfer of gain/loss on sale of emission allowances to Account 254 - Other Regulatory Liabilities for purchasing future emission allowances.

Schedule Page: 310 Line No.: 9 Column: j

Over/under collection of fuel relating to sales to wholesale customers.

Schedule Page: 310 Line No.: 13 Column: i

Subtotal non-RQ of $711,321 includes transmission revenue for OS service of $123,003. Transmission base revenue totals $116,212 and ancillary services revenue totals $6,791.

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 2016/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	2,542,754	2,419,201
5	(501) Fuel	241,232,166	280,051,019
6	(502) Steam Expenses	16,631,366	13,218,658
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	6,020,395	5,537,786
10	(506) Miscellaneous Steam Power Expenses	5,762,431	6,232,820
11	(507) Rents	4,500	1,500
12	(509) Allowances	-137,732	19,389
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	272,055,880	307,480,373
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	91,613	85,716
16	(511) Maintenance of Structures	1,361,389	1,862,262
17	(512) Maintenance of Boiler Plant	12,333,379	12,896,627
18	(513) Maintenance of Electric Plant	11,543,547	12,615,664
19	(514) Maintenance of Miscellaneous Steam Plant	4,513,165	6,265,718
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	29,843,093	33,725,987
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	301,898,973	341,206,360
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	12,421,296	9,399,979
25	(518) Fuel	56,467,219	45,687,791
26	(519) Coolants and Water	2,876,256	3,149,217
27	(520) Steam Expenses	6,316,647	7,326,705
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	1,566,158	2,359,644
31	(524) Miscellaneous Nuclear Power Expenses	41,091,216	37,477,684
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	120,738,792	105,401,020
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	15,200,712	-3,055,152
36	(529) Maintenance of Structures	2,738,627	3,106,875
37	(530) Maintenance of Reactor Plant Equipment	3,069,010	14,474,420
38	(531) Maintenance of Electric Plant	2,500,132	3,416,419
39	(532) Maintenance of Miscellaneous Nuclear Plant	10,319,397	17,185,353
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	33,827,878	35,127,915
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	154,566,670	140,528,935
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	702,170	770,952
45	(536) Water for Power		
46	(537) Hydraulic Expenses	1,286,134	1,398,001
47	(538) Electric Expenses	181,718	162,263
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,089,500	726,151
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	3,259,522	3,057,367
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	152,188	145,819
54	(542) Maintenance of Structures	18,362	7,785
55	(543) Maintenance of Reservoirs, Dams, and Waterways	702,406	1,034,426
56	(544) Maintenance of Electric Plant	3,104,540	3,441,143
57	(545) Maintenance of Miscellaneous Hydraulic Plant	110,419	76,450
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,087,915	4,705,623
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	7,347,437	7,762,990

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 2016/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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,100,946	1,146,657
63	(547) Fuel	165,339,292	185,680,047
64	(548) Generation Expenses	5,023,761	4,757,331
65	(549) Miscellaneous Other Power Generation Expenses	1,554,627	1,617,315
66	(550) Rents	40,800	43,752
67	TOTAL Operation (Enter Total of lines 62 thru 66)	173,059,426	193,245,102
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	345,076	469,644
70	(552) Maintenance of Structures	553,263	584,816
71	(553) Maintenance of Generating and Electric Plant	13,764,550	11,824,623
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	663,459	654,807
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	15,326,348	13,533,890
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	188,385,774	206,778,992
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	254,194,400	282,221,548
77	(556) System Control and Load Dispatching	2,718,759	2,937,877
78	(557) Other Expenses	263,750	267,004
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	257,176,909	285,426,429
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	909,375,763	981,703,706
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	792,884	851,568
84			
85	(561.1) Load Dispatch-Reliability	1,076,009	1,038,723
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	773,525	599,016
87	(561.3) Load Dispatch-Transmission Service and Scheduling	169,113	186,478
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	45,352	48,676
90	(561.6) Transmission Service Studies	3,905	8,136
91	(561.7) Generation Interconnection Studies	-196,944	-191,571
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	437,299	452,676
94	(563) Overhead Lines Expenses	51,577	365,391
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	2,535,425	2,700,581
97	(566) Miscellaneous Transmission Expenses	3,600,428	3,137,388
98	(567) Rents	340,147	329,966
99	TOTAL Operation (Enter Total of lines 83 thru 98)	9,628,720	9,527,028
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	24,142	23,243
102	(569) Maintenance of Structures	27,498	15,526
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	4,839	7,755
105	(569.3) Maintenance of Communication Equipment	31,563	34,319
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,860,584	2,807,075
108	(571) Maintenance of Overhead Lines	5,133,521	5,213,367
109	(572) Maintenance of Underground Lines	15,803	99,900
110	(573) Maintenance of Miscellaneous Transmission Plant	245,447	255,156
111	TOTAL Maintenance (Total of lines 101 thru 110)	8,343,397	8,456,341
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	17,972,117	17,983,369

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 2016/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	846,719	866,816
135	(581) Load Dispatching	973,693	967,713
136	(582) Station Expenses	574,535	605,692
137	(583) Overhead Line Expenses	1,464,753	1,392,041
138	(584) Underground Line Expenses	241,818	236,491
139	(585) Street Lighting and Signal System Expenses	416,277	337,282
140	(586) Meter Expenses	1,075,373	1,512,216
141	(587) Customer Installations Expenses	24,362	15,547
142	(588) Miscellaneous Expenses	7,483,654	7,452,109
143	(589) Rents	2,169,852	2,305,730
144	TOTAL Operation (Enter Total of lines 134 thru 143)	15,271,036	15,691,637
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	247,985	301,837
147	(591) Maintenance of Structures	6,720	10,205
148	(592) Maintenance of Station Equipment	3,516,089	3,663,286
149	(593) Maintenance of Overhead Lines	26,028,775	27,623,945
150	(594) Maintenance of Underground Lines	3,121,335	2,774,804
151	(595) Maintenance of Line Transformers	134,260	167,226
152	(596) Maintenance of Street Lighting and Signal Systems	3,634,155	2,715,852
153	(597) Maintenance of Meters	311,848	302,672
154	(598) Maintenance of Miscellaneous Distribution Plant	2,975,746	2,886,479
155	TOTAL Maintenance (Total of lines 146 thru 154)	39,976,913	40,446,306
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	55,247,949	56,137,943
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,558,673	1,699,047
160	(902) Meter Reading Expenses	1,895,936	1,772,854
161	(903) Customer Records and Collection Expenses	35,636,476	36,529,324
162	(904) Uncollectible Accounts	5,927,251	5,697,561
163	(905) Miscellaneous Customer Accounts Expenses	2,812,218	2,295,274
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	47,830,554	47,994,060

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 2016/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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	278,681	319,698
168	(908) Customer Assistance Expenses	14,392,900	12,828,632
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	98,018	281,313
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	14,769,599	13,429,643
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,195,106	1,504,308
176	(913) Advertising Expenses	1,872	-3,158
177	(916) Miscellaneous Sales Expenses	227,932	253,830
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,424,910	1,754,980
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	63,602,777	56,641,077
182	(921) Office Supplies and Expenses	18,141,449	17,782,876
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	13,514,667	15,282,833
185	(924) Property Insurance	7,022,817	6,719,399
186	(925) Injuries and Damages	6,898,273	6,982,006
187	(926) Employee Pensions and Benefits	55,383,403	39,648,705
188	(927) Franchise Requirements	6,077	8,569
189	(928) Regulatory Commission Expenses	5,244,577	5,324,591
190	(929) (Less) Duplicate Charges-Cr.	8,142,846	8,786,659
191	(930.1) General Advertising Expenses	20,700	157
192	(930.2) Miscellaneous General Expenses	18,051,631	16,226,454
193	(931) Rents	5,078,266	4,779,376
194	TOTAL Operation (Enter Total of lines 181 thru 193)	184,821,791	160,609,384
195	Maintenance		
196	(935) Maintenance of General Plant	6,905,304	6,334,105
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	191,727,095	166,943,489
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,238,347,987	1,285,947,190

Schedule Page: 320 Line No.: 12 Column: b

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: c

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 $13.9 million and $3.3 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 2015, the Company reversed actual outage costs of $20.6 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.

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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Georgia Power (Calhoun Falls)	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	RQ	Schedule #1		543	464
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	Morgan Stanley Capital Group, Inc	OS	Tariff #2			
14	Rainbow Energy Marketing Corporation	OS	Tariff #1			
	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					
2	Agency No. 1	OS				
3	Southern Company Services, Inc	OS	Tariff #4			
4	The Energy Authority, Inc	OS				
5	Duke Energy Carolinas, LLC	OS				
6	Duke Energy Progress, LLC	OS				
7	Saluda Solar I, LLC	OS				
8	TIG Sun Energy III, LLC	OS				
9	Billing Credit Agreement (BCA) DER					
10	Solar Power Purchases	OS				
11	Columbia Energy, LLC	IU	Tariff #1			
12	Southern Company Services, Inc	IF	Tariff #4			
13	Santee Cooper	LF		25		
14	Columbia Energy, LLC	EX	Tariff #5			
	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 2016/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	Adjustments					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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)	
3,550				76,014		76,014	1
802				137,637		137,637	2
26,539				991,033		991,033	3
490				95,032		95,032	4
12,270				365,082		365,082	5
4,007				147,035		147,035	6
692				32,976		32,976	7
49					68,332	68,332	8
2,991,906				193,888,768		193,888,768	9
111,044				3,187,190		3,187,190	10
5,000				221,100		221,100	11
82,837				2,109,123		2,109,123	12
40,254				1,012,427		1,012,427	13
101,105				3,609,960		3,609,960	14
4,978,837	473	1,361	17,495,704	244,322,340	-7,623,644	254,194,400	

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
42,464				1,127,540		1,127,540	2
9,987				353,758		353,758	3
51,360			37,200	1,977,256		2,014,456	4
1,940				97,572		97,572	5
741				43,615		43,615	6
261				11,746		11,746	7
1,005				90,842		90,842	8
							9
271				103,632		103,632	10
1,177,818			9,890,800	26,198,598	188,370	36,277,768	11
307,334			3,539,904	8,287,700		11,827,604	12
5,111			4,027,800	194,833		4,222,633	13
	473	1,361		-38,129		-38,129	14
4,978,837	473	1,361	17,495,704	244,322,340	-7,623,644	254,194,400	

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 2016/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)	
					-7,880,346	-7,880,346	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,978,837	473	1,361	17,495,704	244,322,340	-7,623,644	254,194,400	

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 6/20/1973

Schedule Page: 326 Line No.: 2 Column: c

Contracts for electric service dated 10/3/1975, 5/3/1976 and 2/23/2016.

Schedule Page: 326 Line No.: 3 Column: c

Contract for electric service dated 1/7/1997.

Schedule Page: 326 Line No.: 4 Column: c

Contract for electric service dated 7/29/1996.

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 Edison Electric Institute, Inc. (EEI) Master Power Purchase and Sale Agreement.

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
International Swaps and Derivatives Association (ISDA) Agreement effective 9/1/2005.

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
Tariff #1, Docket No. ER10-2778

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 #4, Docket No. ER10-2881

Schedule Page: 326.1 Line No.: 4 Column: b
OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute, Inc. (EEI) Master Power Purchase and Sale Agreement.

Schedule Page: 326.1 Line No.: 4 Column: c
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2004.

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
FERC Electric Rate Schedule No. 42.

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. 29.

Schedule Page: 326.1 Line No.: 7 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate docket number.

Schedule Page: 326.1 Line No.: 7 Column: c
SCPSC Docket No. 2016-182-E, Order No. 2016-373

Schedule Page: 326.1 Line No.: 8 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate docket number.

Schedule Page: 326.1 Line No.: 8 Column: c
SCPSC Docket No. 2015-363-E, Order No. 2015-788

Schedule Page: 326.1 Line No.: 10 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate docket number.

Schedule Page: 326.1 Line No.: 10 Column: c
SCPSC Docket No. 2015-54-E, Order No. 2015-512

Schedule Page: 326.1 Line No.: 11 Column: b
IU - Service from designated generating unit(s) with duration longer than one year but less than five years.

Schedule Page: 326.1 Line No.: 11 Column: c
Tariff #1, Docket No. ER10-1892

Schedule Page: 326.1 Line No.: 11 Column: l
Scheduling charges

Schedule Page: 326.1 Line No.: 12 Column: b

IF - Firm service with duration longer than one year but less than five years. Contract terminated on 12/31/2016.

Schedule Page: 326.1 Line No.: 12 Column: c

Tariff #4, Docket No. ER10-2881

Schedule Page: 326.1 Line No.: 13 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.: 13 Column: c

Contract for electric service dated 1/7/1997.

Schedule Page: 326.1 Line No.: 14 Column: b

EX - Exchanges of electricity.

Schedule Page: 326.1 Line No.: 14 Column: c

Electric service provided under SCE&G's OATT Schedules 4 and 9.

Schedule Page: 326.1 Line No.: 14 Column: h

Over delivery of energy by Columbia Energy, LLC

Schedule Page: 326.1 Line No.: 14 Column: i

Under delivery of energy by Columbia Energy, LLC

Schedule Page: 326.2 Line No.: 1 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($3,419,418).

Reflects the deferral of short-term capacity purchases from The Energy Authority, Inc. per SCPSC Docket Nos. 2008-230-E and 2012-218-E of ($37,200).

Reflects the deferral of capacity purchases from Columbia Energy, LLC and Southern Company Services, Inc. per SCPSC Docket No. 2013-276-E of ($4,822,104).

Reflects fuel expense of $25,938 for Company-owned fuel oil used by Columbia Energy LLC, for generation.

Reflects the deferral of purchase power of ($206,220) pursuant to SCPSC Docket No. 2015-54-E, under the Company's Distributed Energy Resources (DER) program.

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 2016/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 Progress, LLC	SFP
2				
3	Duke Energy Carolinas, LLC	Georgia Power Company	Duke Energy Carolinas, LLC	SFP
4				
5	Southern Company Services, Inc.	Georgia Power Company	Duke Energy Carolinas, LLC	NF
6				
7	Southern Company Services, Inc.	Duke Energy Carolinas, LLC	Georgia Power Company	NF
8				
9	The Energy Authority, Inc.	Georgia Power Company	South Carolina Public Service	
10			Authority	SFP
11				
12	South Carolina Public Service	South Carolina Public Service	Various	
13	Authority	Authority		FNO
14				
15	Southeastern Power Administration	Southeastern Power	Various	
16		Administration		FNO
17				
18	City of Orangeburg	South Carolina Electric & Gas	City of Orangeburg	
19		Company		FNO
20				
21	Town of Winnsboro	South Carolina Electric & Gas	Town of Winnsboro	
22		Company		FNO
23				
24	Central Electric Power Co-op	South Carolina Public Service	Central Electric Power Co-op	
25		Authority		FNO
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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	CPLE	153	2,400	2,352	1
						2
T5.S7, S1, S2	SOCO	DUK	306	4,000	3,920	3
						4
T5.S8, S1, S2	SOCO	DUK				5
						6
T5.S8, S1, S2	DUK	SOCO		1,552	1,518	7
						8
						9
T5.S7,S1, S2	SOCO	SC	123	2,921	2,863	10
						11
						12
T5, Attach H			655	308,326	299,346	13
						14
						15
T5, Attach H			216	32,499	31,363	16
						17
						18
T5, Attach H			1,596	868,750	843,447	19
						20
						21
T5, Attach H			73	40,512	39,717	22
						23
						24
T5, Attach H			67	27,370	26,832	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			3,189	**1,288,330**	**1,251,358**	

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 2016/Q4

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.
18,980		985	19,965	1
				2
37,960		1,970	39,930	3
				4
15		1	16	5
				6
12,369		669	13,038	7
				8
				9
14,973		852	15,825	10
				11
				12
1,748,934	13,887	95,360	1,858,181	13
				14
				15
591,400		68,332	659,732	16
				17
				18
4,254,064		565,543	4,819,607	19
				20
				21
198,429		25,861	224,290	22
				23
				24
178,360	770	9,731	188,861	25
				26
				27
				28
				29
				30
				31
				32
				33
				34
7,055,484	**14,657**	**769,304**	**7,839,445**	

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.: 3 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 3 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 3 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 5 Column: h
Non-firm hourly billing demand of 2.
Schedule Page: 328 Line No.: 5 Column: i
Customer reserved transmission service, but did not schedule service.
Schedule Page: 328 Line No.: 5 Column: j
Customer reserved transmission service, but did not schedule service.
Schedule Page: 328 Line No.: 5 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 7 Column: h
Non-firm hourly billing demand of 1,692.
Schedule Page: 328 Line No.: 7 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 7 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 7 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 10 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 10 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 10 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 13 Column: e
Also includes Rate Schedules S1, S2 and S4 of Tariff.
Schedule Page: 328 Line No.: 13 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 13 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 13 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.: 13 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 13 Column: n
Network transmission revenue.
Schedule Page: 328 Line No.: 16 Column: e
Also includes Rate Schedules S1, S2, S5 and S6 of Tariff.
Schedule Page: 328 Line No.: 16 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 16 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 16 Column: m

Sum of Ancillary Service 1, 2, 5 and 6 charges.

Schedule Page: 328 Line No.: 16 Column: n

Network transmission revenue.

Schedule Page: 328 Line No.: 19 Column: e

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 19 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 19 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 19 Column: m

Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 19 Column: n

Network transmission revenue.

Schedule Page: 328 Line No.: 22 Column: e

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 22 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 22 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 22 Column: m

Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 22 Column: n

Network transmission revenue.

Schedule Page: 328 Line No.: 25 Column: e

Also includes Rate Schedules S1, S2, and S4 of Tariff.

Schedule Page: 328 Line No.: 25 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 25 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 25 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.: 25 Column: m

Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 25 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 2016/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					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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 2016/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)	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	5,004	5,184	14,496	5,829	15,521	35,846
2	Santee Cooper	SFP	1,800		9,011		1,423	10,434
3	Southern Co Svcs, Inc	SFP	300,818		3,317,472		252,707	3,570,179
4	Adjustments						-1,081,034	-1,081,034
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		307,622	5,184	3,340,979	5,829	-811,383	2,535,425

Schedule Page: 332 Line No.: 1 Column: g

Scheduling, System Control and Dispatch	$ 382
Reactive Supply and Voltage Control	1,823
Regulation and Frequency Response	347
Operating Reserve - Spinning	743
Operating Reserve - Supplement	743
Other - Direct Assignment Charges	11,483
Total	$ 15,521

Schedule Page: 332 Line No.: 2 Column: g

Scheduling, System Control and Dispatch	$ 406
Reactive Supply and Voltage Control	1,017
Total	$ 1,423

Schedule Page: 332 Line No.: 3 Column: g

Scheduling, System Control and Dispatch	$ 96,720
Reactive Supply and Voltage Control	132,000
Other - FERC Annual Charge Recovery	19,510
Other - Recovery of Attachment K Charge Factor	4,477
Total	$ 252,707

Schedule Page: 332 Line No.: 4 Column: g

Columbia Energy LLC Reactive Supply and Voltage Control (RSV) to SCE&G	$ 488,000
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services, Inc. pursuant to SCPSC Docket No. 2013-276-E.	(1,378,779)
Southern Company Services, Inc. refund calculated on Transmission Service for 2015	(194,956)
Southern Company Services, Inc. surcharge calculated on Transmission Service for 2015	5,376
Duke Energy Carolinas refund calculated on Transmission Service for 2015	(675)
Total	($1,081,034)

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	439,129
2	Nuclear Power Research Expenses	611,529
3	Other Experimental and General Research Expenses	947,217
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	259,291
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Other Business Expense	33,584
7	Transportation and Other Power Operated Equipment	27,637
8	Travel excluding Meals	3,148
9	Meals	43
10	Computer Hardware and Software Maintenance	67,888
11	Utilities	13,377
12	Telephone Resource Usage	42,371
13	Director Fees and Expenses	1,654,052
14	Outside Services	94,318
15	Computer Resource Usage, Hardware, Software	
16	and Network Services	105,692
17	Company Payroll	69,367
18	Aircraft Transportation	32,972
19	Depreciation, Amortization and Property Tax Charges	
20	billed from SCANA Services	13,528,020
21	Postage	5,300
22	Research and Development Grant Amortization	100,000
23	Miscellaneous	16,696
24		
25		
26		
27		
28		
29		
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31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	18,051,631

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			5,412,654		5,412,654
2	Steam Production Plant	67,877,522				67,877,522
3	Nuclear Production Plant	19,505,763				19,505,763
4	Hydraulic Production Plant-Conventional	2,364,491				2,364,491
5	Hydraulic Production Plant-Pumped Storage	2,109,166				2,109,166
6	Other Production Plant	24,927,519				24,927,519
7	Transmission Plant	28,750,010				28,750,010
8	Distribution Plant	71,693,390				71,693,390
9	Regional Transmission and Market Operation					
10	General Plant	5,300,199				5,300,199
11	Common Plant-Electric	5,865,540		2,624,476		8,490,016
12	TOTAL	228,393,600		8,037,130		236,430,730

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 V. C. Summer Nuclear Station. The charges were based on plant balances of Saluda - $793,257, Stevens Creek - $2,268,402 and Neal Shoals - $1,507,161. The associated costs of relicensing the V. C. Summer Nuclear Plant through 2042 is $8,564,832.

Amortization of a steam generator at a 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 $69,791,263 are being amortized over the expected life of the software application.

Common Plant - Electric (Account 404):
Amortization of data processing software of $139,438,034 over the expected life of the software application.

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 2016/Q4

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							
20							
21							
22							
23							
24							
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50							

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, as 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.

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 2016/Q4

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).	5,164,078		5,164,078	
6					
7	Company labor, legal and miscellaneous				
8	expenses related to proceedings before the				
9	SCPSC.		35,979	35,979	
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 before the SCPSC.		37,473	37,473	
16					
17					
18	Company labor, legal, consulting and				
19	miscellaneous expenses related to proceedings				
20	before the FERC.		7,370	7,370	
21					
22	Company labor, legal and miscellaneous				
23	expenses associated with the Distributed				
24	Energy Resources Program Act before the SCPSC				
25	Docket No. 2014-214-E.		-323	-323	
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,164,078	80,499	5,244,577	

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 2016/Q4

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	5,164,078					5
							6
							7
							8
Electric	928	35,979					9
							10
							11
							12
							13
							14
Electric	928	37,473					15
							16
							17
							18
							19
Electric	928	7,370					20
							21
							22
							23
							24
Electric	928	-323					25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		5,244,577					46

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	EPRI Coordination
3		Technology Transfer
4	(2) Transmission	EPRI Coordination
5		Technology Transfer
6	(3) Distribution	EPRI Coordination
7		Technology Transfer
8	(6) Other	
9	Power Quality	EPRI Coordination
10		
11	B. Electric R,D and D Performed Externally	
12	(1) Research Support to EPRI	
13	Fossil Steam Plants and Combustion	
14	Turbines - Programs	Boiler and Turbine Steam and Cycle Chemistry
15		Combined Cycle HRSG and Balance of Plant
16		Generation Maintenance Applications Center
17		Operations Management & Technology
18		Coal Combustion Products - Envrionmental Issues
19		Fish Protection at Steam Electric Power Plants
20		Effluent Guidelines and Water Quality Management
21		Power Plant Multimedia Toxics Characterization
22		Air Quality Assessment of Ozone, Particulate Matter, Visibility and
23		Deposition
24	Nuclear Power - Programs	
25		Nuclear Power
26		Steam Turbines, Generators and Balance-of-Plant
27	Transmission and Substation - Programs	
28		Structure and Sub-Grade Corrosion Management
29		Lightning Performance and Grounding of Transmission Lines
30		Line Design Tools and Practices for Construction and Maintenance
31		Polymer and Composite Overhead Transmission Insulators
32		Overhead Line Ratings and Increased Power Flow
33		High Temperature Operation of Overhead Lines
34		Technology Transfer for Underground Transmission
35		Transformer Life Management
36		Substation Physical Security and Intentional Electromagnetic
37		Interference (IEMI)
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 2016/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	Energy Storage and Distributed Generation -	
2	Programs	
3		Strategic Intelligence and Analysis
4	Cyber Security - Programs	
5		Cyber Security and Privacy
6	Fossil Steam Plants and Combustion Turbines -	
7	Supplemental Projects	
8		Plant Decomissioning and Site Closure Interest Group
9	Nuclear - Supplemental Projects	
10		SGMP - Steam Generator Management Program
11		WRTC - Welding & Repair Technology Center
12		FRP - Fuel Reliability Program (QA)
13		Fuel Works / Cask Loader Users Group
14		NDE - Nondestructive Evaluation Applications and Technology (QA)
15		NMAC - Nuclear Maintenance Applications Center
16		Cable Program
17		Nuclear Plant Performance Programs (HXPUG, SWAP, P2EP)
18		SQURTS – Seismic Qualification Reporting and Testing Standardization (QA)
19		Standardized Task Evaluations for Portable Qualifications (STE)
20		Submergence Qualification for Medium-Voltage Cable (QA)
21		CHECWORKS Users Group (CHUG)
22		BPIG - Buried Pipe Integrity Group
23		GOTHIC Advisory Group (QA)
24		HRA Calculator User Group (QA)
25		MAAP Users Group
26		Integrated Risk Technologies Users Group
27		External Data Hazards Collection
28		SMART chemWORKS User Group - Maintenance and Support
29		Fault Tree Reliability Evaluation eXpert (FTREX)
30		Advanced Nuclear Technology (ANT) New Plant Deployment
31		
32	Transmission - Supplemental Projects	
33		Electromagnetic Pulse (EMP) Grid Resilience: Transmission
34		Vulnerability and Mitigation
35	Cyber Security Projects	
36		Cybersecurity Capability Maturity Model Assessment
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 2016/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	(4) Research Support to Others (Classify):	
2	Clemson University Electric	
3	Power Research Association	
4	National Electric Energy Testing and	
5	Research Applications Center	
6	Southeast Coastal Wind Coalition	
7	South Carolina Clean Energy	
8	Business Alliance	
9	South Carolina Biomass Council	
10	Smart Electric Power Alliance	
11	Marketing Research	
12		
13	Total Cost Incurred	
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
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37		
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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
89,642		Various	89,642		2
403		Various	403		3
12,282		Various	12,282		4
8,542		Various	8,542		5
8,862		Various	8,862		6
12,380			12,380		7
					8
3,577		Various	3,577		9
					10
					11
					12
					13
	30,609	930.2	30,609		14
	80,505	930.2	80,505		15
	17,441	930.2	17,441		16
	48,352	930.2	48,352		17
	56,416	930.2	56,416		18
	68,252	930.2	68,252		19
	63,992	930.2	63,992		20
	70,424	930.2	70,424		21
					22
	72,414	930.2	72,414		23
					24
	611,529	930.2	611,529		25
	54,889	517	54,889		26
					27
	10,294	930.2	10,294		28
	18,026	930.2	18,026		29
	14,486	930.2	14,486		30
	16,733	930.2	16,733		31
	11,499	930.2	11,499		32
	13,141	930.2	13,141		33
	9,252	930.2	9,252		34
	35,715	930.2	35,715		35
					36
	12,143	930.2	12,143		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 2016/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
					2
	14,418	930.2	14,418		3
					4
	101,675	930.2	101,675		5
					6
					7
	6,205	921	6,205		8
					9
	68,833	524	68,833		10
	16,085	524	16,085		11
	107,438	524	107,438		12
	12,000	107	12,000		13
	38,667	524	38,667		14
	11,833	524	11,833		15
	2,333	524	2,333		16
	6,400	524	6,400		17
	20,000	524	20,000		18
	11,941	524	11,941		19
	10,000	524	10,000		20
	8,000	524	8,000		21
	10,000	524	10,000		22
	8,000	524	8,000		23
	6,667	524	6,667		24
	8,667	182.3	8,667		25
	21,800	524	21,800		26
	10,000	182.3	10,000		27
	20,000	524	20,000		28
	2,667	524	2,667		29
	137,500	107	137,500		30
					31
					32
					33
	24,352	921	24,352		34
					35
	24,930	930.2	24,930		36
					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 2016/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
					2
	30,000	930.2	30,000		3
					4
	104,000	930.2	104,000		5
	5,000	921	5,000		6
					7
	4,000	921	4,000		8
	50	921	50		9
	21,800	921	21,800		10
	22,500	930.2	22,500		11
					12
135,688	2,213,873		2,349,561		13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
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Schedule Page: 352.2 Line No.: 15 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 2016/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	46,571,491		
4	Transmission	4,529,972		
5	Regional Market			
6	Distribution	6,087,065		
7	Customer Accounts	18,166,885		
8	Customer Service and Informational	2,540,907		
9	Sales	1,013,772		
10	Administrative and General	30,637,259		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	109,547,351		
12	Maintenance			
13	Production	25,921,963		
14	Transmission	2,509,369		
15	Regional Market			
16	Distribution	11,590,936		
17	Administrative and General	1,807,563		
18	TOTAL Maintenance (Total of lines 13 thru 17)	41,829,831		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	72,493,454		
21	Transmission (Enter Total of lines 4 and 14)	7,039,341		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	17,678,001		
24	Customer Accounts (Transcribe from line 7)	18,166,885		
25	Customer Service and Informational (Transcribe from line 8)	2,540,907		
26	Sales (Transcribe from line 9)	1,013,772		
27	Administrative and General (Enter Total of lines 10 and 17)	32,444,822		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	151,377,182	19,068,550	170,445,732
29	Gas			
30	Operation			
31	Production-Manufactured Gas	132,156		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	10,777,013		
37	Customer Accounts	3,571,550		
38	Customer Service and Informational	635,965		
39	Sales	2,921,326		
40	Administrative and General	5,399,054		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	23,437,064		
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	5,726		

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 2016/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	3,729,681		
49	Administrative and General	173,418		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,908,825		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	132,156		
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)	5,726		
57	Distribution (Lines 36 and 48)	14,506,694		
58	Customer Accounts (Line 37)	3,571,550		
59	Customer Service and Informational (Line 38)	635,965		
60	Sales (Line 39)	2,921,326		
61	Administrative and General (Lines 40 and 49)	5,572,472		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	27,345,889	3,323,501	30,669,390
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	178,723,071	22,392,051	201,115,122
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	79,263,254	7,395,922	86,659,176
69	Gas Plant	6,073,554	1,560,502	7,634,056
70	Other (provide details in footnote):		1,409,825	1,409,825
71	TOTAL Construction (Total of lines 68 thru 70)	85,336,808	10,366,249	95,703,057
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,684,555	1,269,990	4,954,545
74	Gas Plant	687,944	100,967	788,911
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,372,499	1,370,957	5,743,456
77	Other Accounts (Specify, provide details in footnote):			
78	Non Utility Property		1,005,326	1,005,326
79	Non Operating Expenses	3,662,722	647,525	4,310,247
80	Other Work in Process	888,371	396,985	1,285,356
81	Other Balance Sheet Payroll	8,847,315	905,108	9,752,423
82				
83				
84				
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86				
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89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	13,398,408	2,954,944	16,353,352
96	TOTAL SALARIES AND WAGES	281,830,786	37,084,201	318,914,987

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.

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 2016/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 2016/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	$139,438,034
118-689 Land and Land Rights	18,841,171
118-690 Structures and Improvements	179,913,733
118-691 Office Furniture and Equipment	12,085,170
118-692 Transportation Equipment	6,592,862
118-693 Stores Equipment	21,011
118-694 Tools, Shop and Garage Equipment	2,119,934
118-695 Laboratory Equipment	151,693
118-696 Power-Operated Equipment	4,579,339
118-697 Communication Equipment	8,158,322
118-698 Miscellaneous Equipment	6,569,743
118-699 ARC Common Gen Plant	673,415
Total	$379,144,427

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
CIS Modernization	$ 7,744,681
CIS Infrastructure	4,559,348
Other Projects < $500K	993,324
Total	$ 13,297,353

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)	$379,144,427	$345,665,974	$33,478,453
Less:			
Common Depreciable Reserve Allocable to Utility Departments (2)	182,626,174	166,500,283	16,125,891
Net Common Plant Allocable to Utility Departments	$196,518,253	$179,165,691	$17,352,562

(1) This allocation is based on functional use by Departments.
Percentage:Electric 91.17% and Gas 8.83%

(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 2016/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					
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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	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 2016/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			97,508	22,702	MW	108,879
2	Reactive Supply and Voltage			622,840	22,702	MW	289,366
3	Regulation and Frequency Response			347	1,719	MW	79,746
4	Energy Imbalance	180	MWH	5,829	479	MWH	14,657
5	Operating Reserve - Spinning			743	1,935	MW	128,683
6	Operating Reserve - Supplement			743	1,935	MW	187,102
7	Other			-1,533,564	1,969	MWH	38,129
8	Total (Lines 1 thru 7)	180		-805,554	53,441		846,562

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	.055781	% Load Ratio Share	$ 382
Santee Cooper OATT Rate Schedule 1	100 MW/1800 MWH	MW, MWH	406
Southern Company Services, Inc. OATT Rate Schedule 1	100 MW/300,818 MWH	MW, MWH	96,720
Total			$ 97,508

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	.055781	% Load Ratio Share	$ 1,823
Santee Cooper OATT Rate Schedule 2	100 MW/1800 MWH	MW, MWH	1,017
Southern Company Services, Inc. OATT Rate Schedule 2	100 MW/300,818 MWH	MW, MWH	132,000
Columbia Energy LLC Reactive Supply and Voltage Control to SCE&G	Flate Rate	Flat Rate	488,000
Total			$ 622,840

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	.055781	% Load Ratio Share	$ 347

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	180	MWH	$ 5,829

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	.055781	% Load Ratio Share	$ 743

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	.055781	% Load Ratio Share	$ 743

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			$ 11,483
Duke Energy Carolinas, LLC refund calculated on Transmission Service for 2015.			(675)
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services, Inc. pursuant to SCPSC Docket No. 2013-276-E			(1,378,779)
Southern Company Services, Inc. refund calculated on Transmission Service for 2015.			(194,956)
Southern Company Services, Inc. surcharge calculated on Transmission Service for 2015.			5,376
Southern Company Services, Inc. FERC Annual Charge Recovery			19,510
Southern Company Services, Inc. Recovery of Attachment K Charge Factor			4,477
Total			($1,533,564)

Schedule Page: 398 Line No.: 7 Column: e

Generator Imbalance breakdown by MWH:

Net Band 1	Over Delivered	Under Delivered
201	474	1,294

Schedule Page: 398 Line No.: 7 Column: g

Generator Imbalance breakdown by dollar amount:

Net Band 1	Over Delivered	Under Delivered*
$6,553	($12,128)	$43,704

* 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 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 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 2016/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	4,567	19	800	4,307	260				
2	February	4,401	10	800	4,150	251				
3	March	3,168	22	800	2,980	188				
4	Total for Quarter 1				11,437	699				
5	April	3,592	29	1700	3,400	192				
6	May	3,978	31	1700	3,778	200				
7	June	4,903	22	1700	4,655	248				
8	Total for Quarter 2				11,833	640				
9	July	5,266	26	1700	4,858	255			153	
10	August	4,804	12	1700	4,572	232				
11	September	4,609	8	1700	4,380	229				
12	Total for Quarter 3				13,810	716			153	
13	October	3,614	3	1600	3,435	179				
14	November	3,698	21	800	3,497	201				
15	December	3,823	16	800	3,601	222				
16	Total for Quarter 4				10,533	602				
17	Total Year to Date/Year				47,613	2,657			153	

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

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 2016/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 2016/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)	22,524,213
3	Steam	6,993,191			
4	Nuclear	5,772,294	23	Requirements Sales for Resale (See instruction 4, page 311.)	928,209
5	Hydro-Conventional	250,162			
6	Hydro-Pumped Storage	519,448	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	18,772
7	Other	6,788,765			
8	Less Energy for Pumping	721,050	25	Energy Furnished Without Charge	8
9	Net Generation (Enter Total of lines 3 through 8)	19,602,810	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	139,281
10	Purchases	4,978,837	27	Total Energy Losses	981,150
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	24,591,633
12	Received	473			
13	Delivered	1,361			
14	Net Exchanges (Line 12 minus line 13)	-888			
15	Transmission For Other (Wheeling)				
16	Received	379,068			
17	Delivered	368,194			
18	Net Transmission for Other (Line 16 minus line 17)	10,874			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	24,591,633			

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 2016/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	2,146,501		4,409	19	800
30	February	1,909,532		4,221	10	800
31	March	1,734,646		3,129	16	1700
32	April	1,703,344		3,602	29	1700
33	May	1,946,291		3,799	31	1700
34	June	2,319,390	83	4,513	22	1700
35	July	2,627,320	2,934	4,807	28	1700
36	August	2,551,426	208	4,660	15	1700
37	September	2,168,613	769	4,249	9	1600
38	October	1,771,592		3,429	3	1600
39	November	1,760,843		3,406	21	800
40	December	1,952,135	15,614	3,900	16	800
41	TOTAL	24,591,633	19,608			

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	1,288,330	1,251,358
Page 401a	379,068	368,194
Difference	909,262	883,164

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 19	868,750	843,447
Page 329 line 22	40,512	39,717
Total	909,262	883,164

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	1,288,330	1,251,358
Page 401a	379,068	368,194
Difference	909,262	883,164

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 19	868,750	843,447
Page 329 line 22	40,512	39,717
Total	909,262	883,164

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 2016/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)	665	98
7	Plant Hours Connected to Load	8784	2901
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	677	62
12	Net Generation, Exclusive of Plant Use - KWh	5772294000	197299000
13	Cost of Plant: Land and Land Rights	880612	2614196
14	Structures and Improvements	305981573	16807159
15	Equipment Costs	900444236	101792778
16	Asset Retirement Costs	22893826	11409896
17	Total Cost	1230200247	132624029
18	Cost per KW of Installed Capacity (line 17/5) Including	1792.2498	1326.2403
19	Production Expenses: Oper, Supv, & Engr	12421296	55541
20	Fuel	56467219	5571573
21	Coolants and Water (Nuclear Plants Only)	2876256	0
22	Steam Expenses	6316647	229936
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1566158	196846
26	Misc Steam (or Nuclear) Power Expenses	41091216	834312
27	Rents	0	0
28	Allowances	0	-10490
29	Maintenance Supervision and Engineering	15200712	25350
30	Maintenance of Structures	2738627	17785
31	Maintenance of Boiler (or reactor) Plant	3069010	141313
32	Maintenance of Electric Plant	2500132	2540125
33	Maintenance of Misc Steam (or Nuclear) Plant	10319397	569511
34	Total Production Expenses	154566670	10171802
35	Expenses per Net KWh	0.0268	0.0516

Line No.	Item (a)	(b)			(c)		
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	905902	0	0	0	2060315	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	63786	0	0	0	1031	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	83.064	2.705	0.000
41	Average Cost of Fuel per Unit Burned	62.330	0.000	0.000	0.000	2.705	0.000
42	Average Cost of Fuel Burned per Million BTU	0.977	0.000	0.000	0.000	2.623	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.028	0.000
44	Average BTU per KWh Net Generation	10011.000	0.000	0.000	0.000	10770.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *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)	420			30		
7	Plant Hours Connected to Load	6067			214		
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	70			0		
12	Net Generation, Exclusive of Plant Use - KWh	1974564000			3009000		
13	Cost of Plant: Land and Land Rights	3212442			9803		
14	Structures and Improvements	82529641			374377		
15	Equipment Costs	459637360			7315937		
16	Asset Retirement Costs	2480639			0		
17	Total Cost	547860082			7700117		
18	Cost per KW of Installed Capacity (line 17/5) Including	1312.6799			196.9339		
19	Production Expenses: Oper, Supv, & Engr	152112			0		
20	Fuel	65329344			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4400			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2232415			0		
26	Misc Steam (or Nuclear) Power Expenses	2136590			0		
27	Rents	0			0		
28	Allowances	-31133			0		
29	Maintenance Supervision and Engineering	29559			0		
30	Maintenance of Structures	178632			0		
31	Maintenance of Boiler (or reactor) Plant	3326394			0		
32	Maintenance of Electric Plant	246148			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	2643628			0		
34	Total Production Expenses	76248089			0		
35	Expenses per Net KWh	0.0386			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	744179	185321	7424	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12263	1031	137191	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	75.855	2.894	67.824	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	81.712	2.894	74.706	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.332	2.806	12.965	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9367.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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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	401			403		
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	6234000			6748000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	350422			683139		
15	Equipment Costs	7472432			9599220		
16	Asset Retirement Costs	0			0		
17	Total Cost	7822854			10282359		
18	Cost per KW of Installed Capacity (line 17/5) Including	285.5056			368.0157		
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: *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)	14	8
7	Plant Hours Connected to Load	27	8
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	102000	27000
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	403946	392049
15	Equipment Costs	1987711	2522079
16	Asset Retirement Costs	0	0
17	Total Cost	2391657	2914128
18	Cost per KW of Installed Capacity (line 17/5) Including	146.5476	178.5618
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: *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			12		
7	Plant Hours Connected to Load	25			20		
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	246000			124000		
13	Cost of Plant: Land and Land Rights	36462			27297		
14	Structures and Improvements	98438			83439		
15	Equipment Costs	3430228			2558279		
16	Asset Retirement Costs	0			0		
17	Total Cost	3565128			2669015		
18	Cost per KW of Installed Capacity (line 17/5) Including	181.5238			135.8969		
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: *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)	48			0		
7	Plant Hours Connected to Load	45			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	491000			0		
13	Cost of Plant: Land and Land Rights	0			339		
14	Structures and Improvements	613695			117179		
15	Equipment Costs	6988620			9245463		
16	Asset Retirement Costs	0			0		
17	Total Cost	7602315			9362981		
18	Cost per KW of Installed Capacity (line 17/5) Including	140.7836			3601.1465		
19	Production Expenses: Oper, Supv, & Engr	377			0		
20	Fuel	49849			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	115335			27303		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	12			0		
29	Maintenance Supervision and Engineering	181			0		
30	Maintenance of Structures	6356			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	65973			57118		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	238083			84421		
35	Expenses per Net KWh	0.4849			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	10393	311	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1030	137191	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.743	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.743	79.288	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.663	13.760	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.069	0.033	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

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 2016/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 2016/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

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)*

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 2016/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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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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 2016/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 2016/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 2016/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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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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)*

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

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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

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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

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 2016/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 2016/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: *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
690			259			0			6
7984			7529			0			7
0			0			0			8
684			250			0			9
684			250			0			10
96			51			1			11
3390308000			910074000			0			12
2119622			15668			5598726			13
136209568			22556971			0			14
757072301			166702890			0			15
-20786500			4407234			0			16
874614991			193682763			5598726			17
1133.2146			659.3231			0			18
1734179			438301			0			19
124322292			21063590			0			20
0			0			0			21
716278			1920123			0			22
0			0			0			23
0			0			0			24
2796001			836863			0			25
1700640			1082626			0			26
0			4500			0			27
-45259			-40734			0			28
9420			25143			0			29
938488			233913			0			30
7977912			938546			0			31
669000			2518769			0			32
690871			1269616			0			33
141509822			30291256			0			34
0.0417			0.0333			0.0000			35
Coal	Oil		Coal	Gas	Oil				36
Tons	Barrels		Tons	MCF	Barrels				37
1396728	27383	0	32080	8356819	986	0	0	0	38
12424	137191	0	12263	1031	137191	0	0	0	39
83.729	66.519	0.000	0.000	2.281	0.000	0.000	0.000	0.000	40
85.892	65.439	0.000	58.396	2.281	137.538	0.000	0.000	0.000	41
3.457	11.357	0.000	2.451	2.214	23.870	0.000	0.000	0.000	42
0.036	0.000	0.000	0.023	0.000	0.000	0.000	0.000	0.000	43
10191.000	0.000	0.000	10254.000	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
36	66	94	6
208	422	246	7
0	0	0	8
39	0	99	9
33	0	88	10
0	2	0	11
4323000	7332000	15325000	12
6047	15850	96047	13
515189	889566	3508613	14
4228943	11544880	34432016	15
0	0	0	16
4750179	12450296	38036676	17
106.6497	148.8558	312.0574	18
0	50211	0	19
0	486644	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	268801	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	1773	0	29
0	2879	0	30
0	0	0	31
0	321162	0	32
0	0	0	33
0	1131470	0	34
0.0000	0.1543	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	121087	332	0	0	0	0	38
0	0	0	1028	137191	0	0	0	0	39
0.000	0.000	0.000	3.672	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.672	127.352	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.571	22.102	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.061	0.464	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

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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
139	0	13	6
1050	0	13	7
0	0	0	8
0	9	16	9
0	9	13	10
9	0	0	11
28307000	0	43000	12
96047	5261	0	13
4542174	57556	505802	14
51503668	3553212	2285871	15
-5340517	0	0	16
50801372	3616029	2791673	17
286.6409	221.5704	142.1422	18
12339	377	0	19
1900787	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
470331	86494	0	25
0	0	0	26
0	0	0	27
-1187	0	0	28
36286	181	0	29
174623	1071	0	30
0	0	0	31
109782	38897	0	32
0	0	0	33
2702961	127020	0	34
0.0955	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Oil								36
MCF	Barrels								37
278566	6914	0	0	0	0	0	0	0	38
1030	137191	0	0	0	0	0	0	0	39
3.924	46.877	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.924	116.956	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.811	20.298	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.044	0.235	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

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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
46	81	470	6
630	678	10870	7
0	0	0	8
49	0	484	9
48	0	458	10
0	3	0	11
23196000	23368000	1941305000	12
0	0	0	13
639892	1941689	4752426	14
24002835	30798496	262816309	15
0	0	0	16
24642727	32740185	267568735	17
418.3825	294.4791	488.4424	18
0	28276	516674	19
0	752471	51937644	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	72555	2723374	25
0	0	0	26
0	0	0	27
0	0	3	28
0	127	4184	29
0	944	357915	30
0	0	0	31
0	1165362	13198754	32
0	0	0	33
0	2019735	68738548	34
0.0000	0.0864	0.0354	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	232483	475	0	14991935	1462	0	38
0	0	0	1031	137191	0	1031	137191	0	39
0.000	0.000	0.000	3.025	0.000	0.000	3.455	0.000	0.000	40
0.000	0.000	0.000	3.025	104.555	0.000	3.455	111.601	0.000	41
0.000	0.000	0.000	2.933	18.146	0.000	3.351	19.368	0.000	42
0.000	0.000	0.000	0.030	0.414	0.000	0.027	0.000	0.000	43
0.000	0.000	0.000	0.000	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: *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
39.28	27.00	27.00	5
30	26	22	6
45	22	23	7
0	0	0	8
0	26	26	9
0	20	20	10
0	0	0	11
370000	261000	230000	12
63759	0	0	13
181877	573403	40292	14
5988507	3272620	3716000	15
0	0	0	16
6234143	3846023	3756292	17
158.7104	142.4453	139.1219	18
0	0	0	19
41492	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
20499	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
198	0	0	29
0	0	0	30
0	0	0	31
155448	0	0	32
0	0	0	33
217637	0	0	34
0.5882	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Oil								36
MCF	Barrels								37
6997	130571	0	0	0	0	0	0	0	38
1029	137191	0	0	0	0	0	0	0	39
3.680	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.680	120.746	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.575	20.955	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.077	0.464	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 2016/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
88	933	0	6
8452	5907	0	7
0	0	0	8
85	924	0	9
85	852	0	10
0	34	0	11
520913148	4784260000	0	12
0	2737068	0	13
0	28193762	0	14
11144060	476934176	0	15
0	0	0	16
11144060	507865006	0	17
112.2149	507.0031	0	18
0	655313	0	19
24722360	110393411	0	20
0	0	0	21
13760629	0	0	22
0	0	0	23
0	0	0	24
0	2754475	-414	25
0	6167	0	26
0	0	0	27
0	-8944	0	28
0	304289	0	29
0	2049	0	30
0	-462	-50324	31
0	6123821	-1243285	32
0	0	-655981	33
38482989	120230119	-1950004	34
0.0739	0.0251	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	34629551	716	0	0	0	0	38
0	0	0	1032	137191	0	0	0	0	39
0.000	0.000	0.000	3.179	84.293	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.179	105.794	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.081	18.361	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.023	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 2016/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 2016/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
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0.00			0.00			0.00			5
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0			0			0			10
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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 2016/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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0.00			0.00			0.00			5
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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 2016/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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0.00			0.00			0.00			5
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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
									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 2016/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
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0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
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0			0			0			9
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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 2016/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
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		0			0			0	16
		0			0			0	17
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		0			0			0	19
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		0			0			0	24
		0			0			0	25
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		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 2016/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
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0.0000	0.0000	0.0000	35

									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 2016/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 2016/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	17
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		0			0			0	19
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		0			0			0	31
		0			0			0	32
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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 2016/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

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

(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 2016/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 2016/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 2016/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 2016/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	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

(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 2016/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

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: 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: 402.2 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: 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. 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, 2016, the Company incurred actual expenses in the amount of $19.5 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: 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 2016/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)	23	198
7	Plant Hours Connect to Load	8,704	8,433
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	5
12	Net Generation, Exclusive of Plant Use - Kwh	44,387,000	130,763,000
13	Cost of Plant		
14	Land and Land Rights	602,632	6,157,073
15	Structures and Improvements	1,894,672	7,718,824
16	Reservoirs, Dams, and Waterways	4,818,228	354,675,505
17	Equipment Costs	5,250,629	13,964,814
18	Roads, Railroads, and Bridges	124,198	233,527
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	12,690,359	382,749,743
21	Cost per KW of Installed Capacity (line 20 / 5)	852.8467	1,846.3567
22	Production Expenses		
23	Operation Supervision and Engineering	76,387	298,226
24	Water for Power	0	0
25	Hydraulic Expenses	42,139	1,024,945
26	Electric Expenses	51,734	26,030
27	Misc Hydraulic Power Generation Expenses	449,073	139,091
28	Rents	0	0
29	Maintenance Supervision and Engineering	37	4,376
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	27,327	77,898
32	Maintenance of Electric Plant	558,687	413,535
33	Maintenance of Misc Hydraulic Plant	7,604	10,349
34	Total Production Expenses (total 23 thru 33)	1,212,988	1,994,450
35	Expenses per net KWh	0.0273	0.0153

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 2016/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
18	0	0	6
8,433	0	0	7
			8
10	0	0	9
8	0	0	10
3	0	0	11
57,309,000	0	0	12
			13
406,315	0	0	14
3,012,157	0	0	15
6,430,203	0	0	16
4,981,247	0	0	17
128,812	0	0	18
0	0	0	19
14,958,734	0	0	20
865.6675	0.0000	0.0000	21
			22
47,926	0	0	23
0	0	0	24
81,664	0	0	25
1,374	0	0	26
29,593	0	0	27
0	0	0	28
197	0	0	29
15,836	0	0	30
184,718	0	0	31
286,356	0	0	32
15,721	0	0	33
663,385	0	0	34
0.0116	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 2016/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)	528
6	Plant Hours Connect to Load While Generating	3,858
7	Net Plant Capability (in megawatts)	576
8	Average Number of Employees	25
9	Generation, Exclusive of Plant Use - Kwh	524,039,000
10	Energy Used for Pumping	721,050,000
11	Net Output for Load (line 9 - line 10) - Kwh	-197,011,000
12	Cost of Plant	
13	Land and Land Rights	22,147,163
14	Structures and Improvements	36,301,570
15	Reservoirs, Dams, and Waterways	74,706,638
16	Water Wheels, Turbines, and Generators	67,489,924
17	Accessory Electric Equipment	19,288,204
18	Miscellaneous Powerplant Equipment	6,484,247
19	Roads, Railroads, and Bridges	1,328,336
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	227,746,082
22	Cost per KW of installed cap (line 21 / 4)	387.9831
23	Production Expenses	
24	Operation Supervision and Engineering	227,020
25	Water for Power	
26	Pumped Storage Expenses	115,105
27	Electric Expenses	29,650
28	Misc Pumped Storage Power generation Expenses	379,853
29	Rents	
30	Maintenance Supervision and Engineering	147,356
31	Maintenance of Structures	2,526
32	Maintenance of Reservoirs, Dams, and Waterways	358,450
33	Maintenance of Electric Plant	1,543,535
34	Maintenance of Misc Pumped Storage Plant	75,776
35	Production Exp Before Pumping Exp (24 thru 34)	2,879,271
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	2,879,271
38	Expenses per KWh (line 37 / 9)	0.0055

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 2016/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
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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) = .0023

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 2016/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	17,703,000	8,824,020
4						
5						
6						
7						
8						
9						
10						
11						
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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
498	239,713		357,630			3
						4
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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 2016/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	115 KV System	Various	115.00	230.00	Various	104.16	15.57	
2	115 KV System	Various	115.00	115.00	Various	1,404.87	100.80	
3	46 KV System	Various	46.00	115.00	Various	42.77		
4	46 KV System	Various	46.00	46.00	Various	578.19	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	Edenwood	Denny Terrace	230.00	230.00	Wood-H	12.16		1
23	Edenwood	McMeekin	230.00	230.00	Various	11.48		1
24	Edenwood	Tie	230.00	230.00	Wood-H	1.45		1
25	Edenwood	Owens Steel	230.00	230.00	Steel-SP	0.41		1
26	Fairfield	Summer	230.00	230.00	Wood-H	2.79		1
27	Goose Creek	Ashley Phos.	230.00	230.00	Wood-H	3.10		1
28	Graniteville Sub #1	Graniteville Sub #2	230.00	230.00	Steel	0.06		1
29	Graniteville	Urquhart	230.00	230.00	Wood-H	11.23		1
30	Hanahan	Bushy Park	230.00	230.00	Wood-H	10.50		1
31	Hopkins	Tap	230.00	230.00	Steel-SP	2.84		1
32	Huron	Tap	230.00	230.00	Wood-H	0.11		1
33	Jasper	Yemassee#1	230.00	230.00	Steel-SP	39.49		2
34	Jasper	Yemassee#2	230.00	230.00	Steel-SP	39.27		2
35	Jasper	Purrysburg(Santee)	230.00	230.00	Steel-SP	1.24		2
36					TOTAL	3,251.73	190.20	91

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 2016/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	Ladson	Ashley Phos.	230.00	230.00	Wood-H	4.60		1
2	Lake Murray	Saluda River #1	230.00	230.00	Steel-SP	6.38		2
3	Lyles	Saluda River #1	230.00	230.00	Steel-SP	4.13		2
4	Lyles	Saluda River #2	230.00	230.00	Steel-SP	0.59		2
5	McMeekin	Parr	230.00	230.00	Wood-H	16.66		1
6	Parr	Denny Terrace	230.00	230.00	Wood-H	21.96		1
7	Parr	Duke	230.00	230.00	Tower		10.90	1
8	Pepperhill	Mateeba	230.00	230.00	Wood-H	7.10		1
9	Pineland	Denny Terrace	230.00	230.00	Steel-SP	8.46		2
10	St. George	Ladson	230.00	230.00	Wood-H	33.00		1
11	St. George	Williams	230.00	230.00	Steel-SP	0.97		1
12	Summer	Denny Terrace	230.00	230.00	Wood-H	4.53		1
13	Summer	Parr #1	230.00	230.00	Wood-H	2.38		1
14	Summer	Parr #2	230.00	230.00	Wood-H	2.26		1
15	Summer	Graniteville	230.00	230.00	Wood-H	63.26		1
16	Summer	Pineland	230.00	230.00	Wood-H	26.83		1
17	Summer	Denny Terrace	230.00	230.00	Wood-H	26.26		1
18	Summerville	Tap	230.00	230.00	Wood-H		0.08	1
19	Timberlake	Tap	230.00	230.00	Wood-SP	8.41		1
20	Urquhart	Fold-in	230.00	230.00	Steel-H	9.55		1
21	VCS1	Killian	230.00	230.00	Steel-SP	3.36		1
22	VCS1	Killian	230.00	230.00	Steel-SP	38.66		2
23	VCS2	Lake Murray #1	230.00	230.00	Steel-SP		20.53	2
24	Vogtle	SRP	230.00	230.00	Steel-H	17.10		1
25	Ward	Tie	230.00	230.00	Wood-H	0.07		1
26	Wateree	Denny Terrace	230.00	230.00	Wood-H	29.94		1
27	Wateree	Edenwood	230.00	230.00	Wood-H	27.80		1
28	Wateree	Sumter	230.00	230.00	Wood-H	0.86		1
29	Wateree	St. George	230.00	230.00	Wood-H	45.60		1
30	Wateree	Pineland	230.00	230.00	Wood-H	38.62		1
31	Wateree	Hercules	230.00	230.00	Wood-H	0.45		1
32	Wateree	Orangeburg	230.00	230.00	Wood-H	27.10		1
33	Wateree-Edenwd	Columbia	230.00	230.00	Steel-H		2.95	2
34	Williams	Wateree	230.00	230.00	Wood-H	10.30		1
35	Williams	Canadys	230.00	230.00	Wood-H	9.60	0.70	1
36					TOTAL	3,251.73	190.20	91

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 2016/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	Williams	Faber Place #1	230.00	230.00	Steel-SP	0.53		2
2	Williams	Faber Place #2	230.00	230.00	Tower-H	13.65	6.71	2
3	Williams	Tie	230.00	230.00	Concrete	0.08		1
4	Williams	DuPont	230.00	230.00	Wood-H	6.60		1
5	Yemassee	Burton	230.00	230.00	Steel-SP	21.31		2
6	Yemassee	Santee	230.00	230.00	Wood-H	2.93		2
7	Underground							
8	33 KV System					0.23		2
9	46 KV System					0.90		1
10	115 KV System					19.88		1
11								
12								
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	3,251.73	190.20	91

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 2016/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
Various	1,307,722	15,474,127	16,781,849					1
Various	35,477,511	353,174,505	388,652,016					2
Various	443,409	3,088,008	3,531,417					3
Various	2,386,526	42,556,250	44,942,776					4
Various	62,375	3,951,491	4,013,866					5
336mcm		31,047	31,047					6
336mcm								7
336mcm	4,930	638,577	643,507					8
	14,317,368	193,398,432	207,715,800					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
Various								23
1272mcm								24
1272mcm								25
1272mcm								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
1272mcm								32
1272mcm								33
1272mcm								34
1272mcm								35
	72,918,094	690,163,933	763,082,027	51,577	5,149,324		5,200,901	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 2016/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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795mcm								1
1272mcm								2
1272mcm								3
1272mcm								4
795mcm								5
795mcm								6
954mcm								7
Various								8
1272mcm								9
795mcm								10
1272mcm								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
795mcm								24
1272mcm								25
Various								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
795mcm								32
1272mcm								33
1272mcm								34
1272mcm								35
	72,918,094	690,163,933	763,082,027	51,577	5,149,324		5,200,901	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 2016/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
								7
250mcm		16,443	16,443					8
750mcm		1,620,606	1,620,606					9
2250kcm	18,918,253	76,214,447	95,132,700					10
				51,577	5,149,324		5,200,901	11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
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								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	72,918,094	690,163,933	763,082,027	51,577	5,149,324		5,200,901	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.: 11 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.: 11 Column: m

Operation expense includes Accounts 563 - Overhead Line Expenses and 564 - Underground Line Expenses.

Schedule Page: 422.2 Line No.: 11 Column: n

Maintenance expense includes Accounts 571 - Maintenance of Overhead Lines and 572 - Maintenance of Underground Lines.

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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	OVERHEAD						
2	Faber Place	James Island	0.98	Steel	14.00	1	1
3	Saluda Hydro	Williams St.	7.93	Steel	11.00	2	2
4	Summerville	Boonehill	0.64	Steel	11.00	2	2
5	Canadys	Williams	1.02	Steel	4.00	1	1
6	Church Creek	Yemassee	-17.00	Various	16.00	1	1
7	Orchids Paper Tap		1.03	Steel	19.00	1	1
8							
9							
10							
11							
12							
13							
14							
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38							
39							
40							
41							
42							
43							
44	TOTAL		-5.40		75.00	8	8

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)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	Line No.
									1
1272	ACSR		115		846,581			846,581	2
1272	ACSR		115		6,799,845	2,664,250		9,464,095	3
1272	ACSR		115		146,233	52,704		198,937	4
1272	ACSR		230		1,634,461	275,344		1,909,805	5
795	ACSR		115		-277,266	-536,343		-813,609	6
1272	ACSR		46	49,463	433,572	349,336		832,371	7
									8
									9
									10
									11
									12
									13
									14
									15
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									40
									41
									42
									43
				49,463	9,583,426	2,805,291		12,438,180	44

Schedule Page: 424 Line No.: 6 Column: a

Negative numbers in columns (c), (m), (n) and (p) represent retirements in Sections 35 and 50. Since the line was altered, this activity is being reported in accordance with Instruction No. 1 of this schedule.

Schedule Page: 424 Line No.: 7 Column: k

Design Voltage 115

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 2016/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Transmission Substations:				
2	Aiken, Aiken County	Trans-U	115.00	46.00	
3	Aiken, Aiken County	Trans-U	115.00	12.00	
4	Barnwell, Barnwell County	Trans-U	115.00	46.00	
5	Batesburg, City of Batesburg	Trans-U	115.00	33.00	
6	Bayview, Mt. Pleasant City	Trans-U	115.00	23.00	
7	Blackville 115-46KV, Barnwell County	Trans-U	115.00	46.00	
8	Burton Transmission, Beaufort County	Trans-U	230.00	115.00	
9	Burton Transmission, Beaufort County	Trans-U	115.00	46.00	
10	Calhoun County, Calhoun County	Trans-U	115.00	46.00	
11	Calhoun Falls, Calhoun Falls City	Trans-U	115.00	46.00	
12	Calhoun Falls, Calhoun Falls City	Trans-U	46.00	12.00	
13	Canadys Sub, Colleton County	Trans-U	230.00	115.00	
14	Charleston, Charleston County	Trans-U	115.00	23.00	
15	Church Creek, Charleston County	Trans-U	230.00	115.00	
16	Coit Gas Turbine, Richland County	Trans-U	13.80	33.00	
17	Coit, Richland County	Trans-U	115.00	23.00	
18	Coit, Richland County	Trans-U	115.00	33.00	
19	Columbia Industrial Park, Richland County	Trans-U	230.00	115.00	
20	Cope, Orangeburg County	Trans-U	230.00	115.00	
21	Cope, Orangeburg County	Trans-U	115.00	230.00	
22	Denmark, City of Denmark	Trans-U	115.00	46.20	
23	Denny Terrace, Richland County	Trans-U	230.00	115.00	
24	Edenwood, City of Cayce	Trans-U	230.00	115.00	
25	Faber Place, City of North Charleston	Trans-U	115.00	23.00	
26	Faber Place, City of North Charleston	Trans-U	230.00	115.00	
27	Fairfax, Allendale County	Trans-U	115.00	46.20	
28	Fairfield Pumped Storage, Fairfield County	Trans-U	13.80	230.00	
29	Goose Creek, Hanahan City	Trans-U	230.00	115.00	
30	Graniteville #1, Aiken County	Trans-U	115.00	46.00	
31	Graniteville #1, Aiken County	Trans-U	230.00	115.00	
32	Graniteville #2, Aiken County	Trans-U	230.00	115.00	
33	Hagood Gas Turbine, Charleston County	Trans-U	13.80	115.00	
34	Hagood Gas Turbine, Charleston County	Trans-U	13.20	115.00	
35	Hagood Gas Turbine, Charleston County	Trans-U	13.80	4.16	
36	Hamlin, Charleston County	Trans-U	115.00	25.00	
37	Hampton, Hampton County	Trans-U	115.00	46.00	
38	Hanahan, Hanahan City	Trans-U	115.00	25.00	
39	Hanahan, Hanahan City	Trans-U	115.00	46.00	
40	Hardeeville Gas Turbine, Jasper County	Trans-U	13.20	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 2016/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.
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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	Hardeeville, Jasper County	Trans-U	115.00	46.00	
2	Hobcaw, Charleston County	Trans-U	115.00	24.94	
3	Hopkins, Richland County	Trans-U	230.00	115.00	
4	Jasper Gas Turbine, Jasper County	Trans-U	18.00	230.00	
5	Jasper Gas Turbine, Jasper County	Trans-U	21.00	230.00	
6	Kendrick, Richland County	Trans-U	115.00	23.00	
7	Kendrick, Richland County	Trans-U	115.00	33.00	
8	Killian, Richland County	Trans-U	230.00	115.00	
9	Lake Murray, Lexington County	Trans-U	230.00	115.00	
10	Lyles, Richland County	Trans-U	230.00	115.00	
11	Lyles, Richland County	Trans-U	115.00	23.00	
12	Lyles, Richland County	Trans-U	115.00	35.00	
13	Lyles, Richland County	Trans-U	33.00	4.80	
14	McCormick, McCormick County	Trans-U	115.00	46.00	
15	McMeekin, Lexington County	Trans-U	13.80	115.00	
16	Orangeburg #1, Orangeburg County	Trans-U	115.00	46.00	
17	Orangeburg East 230KV, Orangeburg County	Trans-U	230.00	115.00	
18	Parr Gas Turbine, Fairfield County	Trans-U	13.20	115.00	
19	Parr Hydro, Fairfield County	Trans-U	2.30	13.80	
20	Parr Steam, Fairfield County	Trans-U	115.00	13.20	
21	Pepperhill, Charleston County	Trans-U	230.00	115.00	
22	Pineland, Richland County	Trans-U	230.00	115.00	
23	Rader, Richland County	Trans-U	115.00	23.00	
24	Ridgeville, City of Ridgeville	Trans-U	115.00	46.00	
25	Ritter, Colleton County	Trans-U	230.00	115.00	
26	Saluda Hydro, Lexington County	Trans-U	13.20	115.00	
27	Saluda Hydro, Lexington County	Trans-U	115.00	23.00	
28	Saluda Hydro, Lexington County	Trans-U	115.00	13.20	
29	Saluda River, Lexington County	Trans-U	230.00	115.00	
30	Santee, Orangeburg County	Trans-U	230.00	46.20	
31	Santee, Orangeburg County	Trans-U	115.00	46.00	
32	Santee, Orangeburg County	Trans-U	230.00	115.00	
33	Savannah River, Federal Property	Trans-U	230.00	115.00	
34	St. Andrews, Charleston City	Trans-U	115.00	23.00	
35	St. George, Dorchester County	Trans-U	115.00	46.00	
36	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	2.30	46.00	
37	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	46.00	2.30	
38	Stevens Creek Sub, Columbia Cnty Ga.	Trans-U	115.00	46.20	
39	Summerville, Berkeley County	Trans-U	230.00	115.00	
40	Thomas Island, Charleston County	Trans-U	115.00	23.00	

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1	Trenton, Edgefield County	Trans-U	115.00	23.00	
2	Trenton, Edgefield County	Trans-U	115.00	33.00	
3	Trenton, Edgefield County	Trans-U	115.00	46.00	
4	Urquhart 115KV, Aiken County	Trans-U	115.00	13.20	
5	Urquhart 115-46KV, Aiken County	Trans-U	115.00	46.00	
6	Urquhart 230KV, Aiken County	Trans-U	18.00	230.00	
7	Urquhart Gas Turbine, Aiken County	Trans-U	13.20	115.00	
8	V. C. Summer Substation, Fairfield County	Trans-U	22.00	242.00	
9	Ward, Saluda County	Trans-U	230.00	115.00	
10	Ward, Saluda County	Trans-U	115.00	23.00	
11	Ward, Saluda County	Trans-U	115.00	33.00	
12	Wateree Plant, Richland County	Trans-U	21.00	230.00	
13	Wateree Plant, Richland County	Trans-U	230.00	13.80	
14	Williams Gas Turbine, Berkeley County	Trans-U	13.20	115.00	
15	Williams St., Columbia City	Trans-U	115.00	33.00	
16	Williams St., Columbia City	Trans-U	115.00	23.00	
17	Williams Station, Berkeley County	Trans-U	20.00	242.00	
18	Williams Station, Berkeley County	Trans-U	115.00	230.00	
19	Williams Station, Berkeley County	Trans-U	230.00	4.16	
20	Williams Station, Berkeley County	Trans-U	230.00	23.00	
21	Williston Industrial Park , Barnwell County	Trans-U	115.00	46.00	
22	Yemassee, City of Yemassee	Trans-U	230.00	115.00	
23					
24	Distribution Substations:				
25	Adams Run, Charleston County	Dist-U	115.00	23.00	
26	Adams Run, Charleston County	Dist-U	115.00	46.00	
27	Aiken #2, Aiken County	Dist-U	115.00	12.00	
28	Aiken #3, Aiken County	Dist-U	115.00	12.00	
29	Aiken Hampton Avenue, Aiken City	Dist-U	115.00	12.00	
30	Aiken Industrial Park, Aiken City	Dist-U	46.00	23.00	
31	Aiken-Steifeltown, Aiken County	Dist-U	115.00	12.00	
32	Allendale, Allendale City	Dist-U	115.00	12.00	
33	Arrowwood Road, Richland County	Dist-U	115.00	23.00	
34	Ashley Phosphate, City of North Charleston	Dist-U	115.00	23.00	
35	Bacon's Bridge, Summerville City	Dist-U	115.00	23.00	
36	Baldock, Allendale County	Dist-U	115.00	12.00	
37	Bamberg Central, Bamberg City	Dist-U	43.80	12.00	
38	Barnwell City, Barnwell City	Dist-U	46.00	12.00	
39	Barnwell Heights, Barnwell City	Dist-U	46.00	12.00	
40	Barnwell Industrial Park, Barnwell County	Dist-U	43.80	12.00	

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1	Batesburg City, Lexington County	Dist-U	33.00	8.00	
2	Bayfront, Charleston City	Dist-U	115.00	23.00	
3	Beaufort Central, Beaufort City	Dist-U	115.00	12.00	
4	Beaufort Industrial Park, Beaufort County	Dist-U	115.00	12.00	
5	Bee Street, Charleston County	Dist-U	115.00	14.40	
6	Beech Island, Aiken County	Dist-U	46.00	12.00	
7	Bellwright, Berkeley County	Dist-U	115.00	23.00	
8	Belmont, Richland County	Dist-U	115.00	23.00	
9	Belvedere, North Augusta City	Dist-U	115.00	12.00	
10	Blackville 46-12KV, Barnwell County	Dist-U	46.00	12.00	
11	Bluffton, Beaufort County	Dist-U	115.00	23.00	
12	Blythewood, Richland County	Dist-U	115.00	23.00	
13	Boney Rd. , Fairfield County	Dist-U	115.00	23.00	
14	Boney Rd. , Fairfield County	Dist-U	115.00	23.00	
15	Boone Hill, Dorchester County	Dist-U	115.00	23.00	
16	Bowman, Orangeburg County	Dist-U	115.00	8.00	
17	Brookwood, West Columbia City	Dist-U	115.00	23.00	
18	Burton Central, Beaufort County	Dist-U	115.00	12.00	
19	CAE Industrial Park, Lexington County	Dist-U	115.00	23.00	
20	Cainhoy, Berkeley County	Dist-U	115.00	23.00	
21	Calhoun Street, Columbia City	Dist-U	115.00	8.00	
22	Callawassie Island, Jasper County	Dist-U	115.00	23.00	
23	Carlisle, Carlisle City	Dist-U	115.00	23.00	
24	Center Sub, Aiken County	Dist-U	46.00	23.00	23.00
25	Charleston Airport, N Charleston City	Dist-U	115.00	23.00	
26	Charlotte Street, Charleston City	Dist-U	115.00	14.40	
27	Church Creek, Charleston City	Dist-U	115.00	23.00	
28	Circle Drive, Richland County	Dist-U	115.00	8.00	
29	Clearwater, Aiken County	Dist-U	115.00	12.00	
30	Cloverleaf, Aiken County	Dist-U	115.00	12.00	
31	Colonial Heights, Richland County	Dist-U	115.00	23.00	
32	Columbia Airport, Springdale City	Dist-U	115.00	23.00	
33	Columbia Industrial Park, Richland County	Dist-U	115.00	23.00	
34	Congaree Creek, Cayce City	Dist-U	115.00	23.00	
35	Congaree Vista, Richland County	Dist-U	115.00	23.00	
36	Coosaw, Charleston County	Dist-U	115.00	23.00	
37	Cromer Rd, Lexington County	Dist-U	115.00	23.00	
38	Deer Park, Charleston County	Dist-U	115.00	23.00	
39	Denmark Industrial Park, Denmark City	Dist-U	46.00	12.00	
40	Dentsville, Richland County	Dist-U	115.00	23.00	

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1	Dixiana, Lexington County	Dist-U	115.00	23.00	
2	East Columbia, Richland County	Dist-U	115.00	23.00	
3	Edmund, Lexington County	Dist-U	115.00	23.00	
4	Estill Southside, Estill City	Dist-U	46.00	12.00	
5	Estill, Estill City	Dist-U	46.00	13.80	
6	Eutawville, Orangeburg County	Dist-U	115.00	23.00	
7	Fairfax Central, Fairfax City	Dist-U	46.00	12.00	
8	Five Points, Columbia City	Dist-U	115.00	8.00	
9	Fort Johnston Road, Charleston County	Dist-U	115.00	23.00	
10	Frogmore, Beaufort County	Dist-U	115.00	23.00	
11	Gardens Corner, Beaufort County	Dist-U	115.00	23.00	
12	Gaston, Lexington County	Dist-U	115.00	23.00	
13	Gilbert, Lexington County	Dist-U	115.00	23.00	
14	Gills Creek, Richland County	Dist-U	115.00	23.00	
15	Grays Hill, Beaufort County	Dist-U	115.00	12.00	
16	Greengate, Richland County	Dist-U	115.00	23.00	
17	Grove Street, Charleston City	Dist-U	115.00	14.40	
18	Hampton City, Hampton County	Dist-U	46.00	12.00	
19	Hanahan Switching, Berkeley County	Dist-U	46.00	4.16	
20	Harbison, Lexington County	Dist-U	115.00	23.00	
21	Hardeeville, Hardeeville City	Dist-U	115.00	23.00	
22	Herrin, Allendale County	Dist-U	46.00	12.00	
23	Holly Hill, Holly Hill City	Dist-U	115.00	23.00	
24	Houndslake, Aiken County	Dist-U	115.00	12.00	
25	Howard Street, Richland County	Dist-U	33.00	8.00	
26	Irmo Town, Irmo City	Dist-U	115.00	23.00	
27	Isle of Palms, Isle of Palms City	Dist-U	115.00	23.00	
28	Jackson 46-12kV, Aiken County	Dist-U	46.00	12.00	
29	Jackson Street, Columbia City	Dist-U	115.00	8.00	
30	James Island, Charleston County	Dist-U	115.00	23.00	
31	James Prioleau, Charleston County	Dist-U	115.00	23.00	
32	Jasper Construction, Jasper County	Dist-U	115.00	23.00	
33	Johnston 115-23KV, Edgefield County	Dist-U	115.00	23.00	
34	Kilbourne Park, Richland County	Dist-U	115.00	23.00	
35	Killian, Richland County	Dist-U	115.00	23.00	
36	Kingswood, Richland County	Dist-U	115.00	23.00	
37	Kronotex, Barnwell County	Dist-U	115.00	12.00	
38	Ladies Island, Beaufort County	Dist-U	115.00	23.00	
39	Lake Carolina, Richland County	Dist-U	115.00	23.00	
40	Lake Murray Training, Lexington County	Dist-U	115.00	23.00	

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1	Langley, Aiken County	Dist-U	115.00	12.00	
2	Laurel Bay 115-12KV, Beaufort County	Dist-U	115.00	12.00	
3	Leesville 115-23KV, Lexington County	Dist-U	115.00	23.00	
4	Lexington 115-23kV, Lexington County	Dist-U	115.00	23.00	
5	Lexington East Side, Lexington County	Dist-U	115.00	23.00	
6	Lexington Industrial Park, Lexington County	Dist-U	115.00	23.00	
7	Lexington West Side, Lexington County	Dist-U	115.00	23.00	
8	Lower Richland, Richland County	Dist-U	115.00	23.00	
9	Maryville, Charleston County	Dist-U	115.00	23.00	
10	McCormick City 115-13KV, McCormick Cnty	Dist-U	115.00	12.00	
11	Meadowbrook, Beaufort County	Dist-U	115.00	23.00	
12	Meeting Street, Charleston County	Dist-U	115.00	14.40	
13	Middleburg Mall, Richland County	Dist-U	115.00	8.00	
14	Midway, Union County	Dist-U	115.00	13.80	
15	Midway, Union County	Dist-U	23.00	2.40	
16	Mt Pleasant, Charleston County	Dist-U	115.00	23.00	
17	Muller Avenue, Richland County	Dist-U	115.00	8.00	
18	Muller Avenue, Richland County	Dist-U	115.00	23.00	
19	Navy Yard 115-23kV, Federal Property, SC	Dist-U	115.00	23.00	
20	Navy Yard 115-23kV, Federal Property, SC	Dist-U	115.00	13.80	
21	Neeses, Orangeburg County	Dist-U	46.00	8.00	
22	Network, Richland County	Dist-U	115.00	13.80	
23	North 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
24	North Augusta, Aiken City	Dist-U	115.00	12.00	
25	North Bridge Terrace, Charleston County	Dist-U	115.00	23.00	
26	North Naval Weapons, Federal Property	Dist-U	115.00	13.80	
27	North Rhett, North Charleston City	Dist-U	115.00	23.00	
28	Northpointe Business Park, Charleston County	Dist-U	115.00	23.00	
29	Northwoods Mall, North Charleston City	Dist-U	230.00	23.00	
30	Okatie, Jasper County	Dist-U	115.00	23.00	
31	Old Fort, Dorchester County	Dist-U	115.00	23.00	
32	Osceola Park, Charleston County	Dist-U	115.00	23.00	
33	Palmetto Commerce Park, Charleston City	Dist-U	115.00	23.00	
34	Park Street, Columbia City	Dist-U	33.00	13.80	13.80
35	Parr 13.2-23KV, Fairfield County	Dist-U	23.00	13.80	
36	Parr Hill 115-23kV, Fairfield County	Dist-U	115.00	23.00	
37	Pine Hill 230-23kV, Dorchester County	Dist-U	230.00	23.00	
38	Pelion, Lexington County	Dist-U	115.00	23.00	
39	Pendleton Street, Columbia City	Dist-U	115.00	8.00	
40	Piney Woods Road, Richland County	Dist-U	115.00	23.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Platt Springs Rd., Lexington County	Dist-U	115.00	23.00	
2	Platt Springs Rd., Lexington County	Dist-U	115.00	23.00	
3	Pontiac, Richland County	Dist-U	230.00	23.00	
4	Port Park, Hanahan City	Dist-U	115.00	23.00	
5	Port Royal, Port Royal City	Dist-U	115.00	12.00	
6	Pritchardville, Beaufort County	Dist-U	115.00	23.00	
7	Quail Hollow, Lexington County	Dist-U	115.00	23.00	
8	Raborn Pointe, North Augusta City	Dist-U	115.00	12.00	
9	Rantowles, Charleston County	Dist-U	115.00	23.00	
10	Red House Rd, Charleston County	Dist-U	46.00	23.00	
11	Richland Mall, Forest Acres City	Dist-U	115.00	8.00	
12	Ridgeland, Jasper County	Dist-U	115.00	23.00	
13	Riverland Terrace, Charleston County	Dist-U	115.00	23.00	
14	Riverland Terrace, Charleston County	Dist-U	23.00	4.16	
15	Rosewood, Columbia City	Dist-U	33.00	8.00	
16	S. C. Research Association, Richland County	Dist-U	115.00	23.00	
17	Sage Mill Ind Park, Aiken County	Dist-U	115.00	12.00	
18	Saluda County, Saluda County	Dist-U	115.00	23.00	
19	Sandhill, Richland County	Dist-U	115.00	23.00	
20	Santee 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
21	Savage Road, Charleston County	Dist-U	115.00	23.00	
22	Saxe Gotha Industrial Park, Lexington County	Dist-U	115.00	23.00	
23	Seven Mile, North Charleston City	Dist-U	115.00	23.00	
24	Shell Point, Beaufort County	Dist-U	46.00	12.00	
25	Silver Bluff Rd, Aiken County	Dist-U	115.00	12.00	
26	S-Lubeca, Richland County	Dist-U	115.00	12.00	
27	South Main, Columbia City	Dist-U	115.00	8.00	
28	Sparkleberry, Richland County	Dist-U	115.00	23.00	23.00
29	Sparkleberry, Richland County	Dist-U	115.00	23.00	
30	Springdale, Lexington County	Dist-U	115.00	23.00	
31	St. George 115-12kV, Dorchester County	Dist-U	115.00	12.00	
32	St. Helena Island, Beaufort County	Dist-U	115.00	23.00	
33	St. Matthews 46-23kV, Calhoun County	Dist-U	46.00	23.00	23.00
34	Stono Park, Charleston City	Dist-U	115.00	23.00	
35	Summer Construction, Fairfield County	Dist-U	115.00	23.00	
36	Summerville Central, Berkeley County	Dist-U	115.00	23.00	
37	Summerville Industrial Park, Dorchester County	Dist-U	115.00	23.00	
38	Summerville Plaza, City of Summerville	Dist-U	115.00	23.00	
39	Summerville-Ladson, Charleston County	Dist-U	115.00	23.00	
40	Swansea, Lexington County	Dist-U	46.00	23.00	

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1	Sweetwater, Aiken County	Dist-U	115.00	12.00	
2	Ten Mile, Charleston County	Dist-U	115.00	23.00	
3	Terminal, Richland County	Dist-U	33.00	8.00	
4	Timberlake, Lexington County	Dist-U	230.00	23.00	
5	Uptown, Columbia City	Dist-U	115.00	23.00	
6	Uptown, Columbia City	Dist-U	115.00	8.00	
7	Varnville, Varnville City	Dist-U	46.00	12.00	
8	Victory Gardens, Columbia City	Dist-U	115.00	8.00	
9	Wagener, Wagnener City	Dist-U	46.00	8.00	
10	Walterboro 115-23KV, Walterboro City	Dist-U	115.00	23.00	
11	Walterboro Forest Hill, Walterboro City	Dist-U	115.00	23.00	
12	Walterboro Ind Park, Walterboro City	Dist-U	115.00	23.00	
13	Walterboro Southside, Walterboro City	Dist-U	115.00	23.00	
14	West Columbia, West Columbia City	Dist-U	33.00	8.00	
15	White Gables, Dorchester County	Dist-U	115.00	23.00	
16	White Rock, Richland County	Dist-U	115.00	23.00	
17	Whitehall, Lexington County	Dist-U	115.00	23.00	
18	Williston, Williston City	Dist-U	115.00	12.00	
19	Winnsboro, Winnsboro City	Dist-U	115.00	23.00	
20	Woodfield Park, Richland County	Dist-U	115.00	23.00	
21	Yemassee Central, Yemassee City	Dist-U	115.00	23.00	
22					
23	Distribution Substations				
24	Under 10,000 KVA (36)	Dist-U			
25					
26	FUNCTIONAL SUMMARY OF CAPACITY				
27	Transmission Substations				
28	Distribution Substations				
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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.
						1
28	1					2
22	1					3
56	2					4
28	1					5
75	2	1				6
28	1					7
224	1					8
112	2	4				9
28	1					10
50	2	2				11
7	1					12
224	1	1				13
67	2					14
672	2					15
56	2					16
22	1					17
56	1					18
336	1					19
224	1					20
549	1					21
56	2					22
672	2					23
448	2					24
73	3					25
672	2	1				26
56	2					27
717	4	1				28
336	1					29
56	2					30
448	2					31
336	1					32
60	1					33
147	1					34
6	1					35
140	4					36
84	3	2				37
78	3					38
56	2					39
14	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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
28	1					1
28	1					2
336	1					3
700	3					4
500	1					5
56	2	1				6
56	1					7
336	1					8
672	2	1				9
336	1	1				10
56	2					11
56	1					12
8	3					13
58	2	1				14
350	2					15
81	3					16
672	2					17
98	2	1				18
25	3					19
34	1					20
336	1					21
672	2	1				22
45	2					23
28	1					24
336	1					25
133	3					26
65	2					27
133	2					28
336	1					29
28	1					30
28	1					31
140	1					32
672	2					33
22	1					34
28	1					35
14	2					36
14	2					37
28	1	1				38
672	2					39
75	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 2016/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.
22	1	1				1
23	3					2
56	2					3
325	6	2				4
48	2					5
467	1	1				6
176	3	1				7
1232	1	1				8
364	2	1				9
22	1					10
28	1					11
1008	2	1				12
75	2					13
70	1					14
106	4	1				15
60	2					16
785	1	1				17
560	2					18
93	2					19
101	2					20
32	6					21
784	3					22
						23
						24
50	2					25
112	2					26
50	2					27
50	2					28
28	1					29
11	1					30
22	1					31
22	1					32
22	1					33
82	3					34
37	1					35
22	1					36
14	2					37
11	1					38
11	1					39
11	1					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 2016/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.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
40	1					2
28	1					3
22	1					4
202	4					5
11	1					6
28	1					7
50	2					8
50	2					9
11	1					10
56	2					11
77	2					12
23	1					13
22	1					14
60	2					15
11	1					16
28	1					17
56	2					18
28	1					19
56	2					20
22	1					21
28	1	1				22
13	4	1				23
11	1					24
40	1					25
101	4					26
75	2					27
22	1					28
28	1					29
22	1					30
22	1					31
22	1					32
40	1					33
28	1					34
37	1					35
37	1					36
37	1					37
45	2					38
11	1	1				39
45	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 2016/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.
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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.
65	2					1
28	1					2
22	1					3
14	1	1				4
14	1					5
50	2					6
18	2					7
22	1					8
50	2					9
28	1					10
22	1					11
50	2					12
22	1					13
37	1					14
22	1					15
37	1					16
22	1					17
21	2					18
14	2	1				19
50	2					20
28	1	1				21
11	1					22
50	4	1				23
28	1					24
11	1					25
56	2					26
50	2					27
11	1					28
22	1					29
45	2					30
28	1					31
11	1					32
22	1					33
60	2					34
37	1					35
50	2					36
28	1					37
50	2					38
65	2					39
22	1					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 2016/Q4

SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
22	1					1
28	1					2
28	1					3
65	2	1				4
37	1					5
60	2	1				6
75	2					7
60	2					8
37	1					9
11	1	1				10
22	1					11
22	1					12
22	1					13
20	1	1				14
1	3					15
77	2					16
22	1					17
28	1					18
28	1					19
22	1					20
11	1					21
67	3					22
11	1					23
28	1					24
45	2					25
11	1					26
28	1					27
37	1					28
75	2	1				29
28	1					30
60	2					31
75	2					32
65	2					33
44	2	1				34
22	1					35
22	1					36
37	1					37
22	1	1				38
45	2					39
22	1					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 2016/Q4

SUBSTATIONS (Continued)

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28	1					1
22	1					2
75	2					3
22	1					4
28	1					5
37	1					6
37	1	2				7
22	1					8
28	1					9
45	2	1				10
45	2					11
22	1	1				12
22	1					13
4	1					14
21	2					15
22	1					16
28	1					17
22	1					18
75	2					19
21	2					20
45	2					21
37	1					22
22	1					23
25	2	1				24
22	1					25
22	1					26
22	1					27
37	1					28
37	1					29
45	2	1				30
28	1					31
50	2					32
23	2	1				33
37	1					34
22	1					35
40	1					36
50	2					37
37	1					38
60	2					39
11	1	1				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 2016/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.
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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.
28	1	1				1
22	1					2
11	1					3
37	1	1				4
37	1	1				5
23	1					6
11	1					7
22	1					8
11	1					9
22	1					10
40	1					11
28	1					12
22	1					13
18	2					14
37	1					15
50	2	1				16
22	1					17
22	1					18
45	2					19
45	2					20
22	1					21
						22
6719						23
203						24
						25
						26
22047						27
6922						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.7 Line No.: 24 Column: c

Various

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 2016/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	SEMI	803/547	111,453,041
3	Refined Coal Purchases	Canadys Refined Coal, LLC	419	64,468,085
4				
5				
6				
7				
8				
9				
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	454/493	5,165,616
22	Coal Sales	Canadys Refined Coal, LLC	419	64,062,406
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column: b

See page 102 for abbreviations used for Affiliated Companies.

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 billing period.

REPORTING BUSINESS UNIT	Category	FERC Account	Direct Billed	Allocated	Total Billed
SCEG	Corporate Security	1070	145,919	42,234	188,154
SCEG	Corporate Security	1080	13,854	0	13,854
SCEG	Corporate Security	1180	10,619	4,643	15,262
SCEG	Corporate Security	1630	1,368	0	1,368
SCEG	Corporate Security	1823	246,121	0	246,121
SCEG	Corporate Security	1860	0	3,295	3,295
SCEG	Corporate Security	4081	173,255	27,811	201,065
SCEG	Corporate Security	4210	0	3,509	3,509
SCEG	Corporate Security	4261	0	2,998	2,998
SCEG	Corporate Security	4265	81,297	11,803	93,101
SCEG	Corporate Security	9040	(1,602)	0	(1,602)
SCEG	Corporate Security	9050	391	0	391
SCEG	Corporate Security	9200	2,454,399	394,100	2,848,499
SCEG	Corporate Security	9210	747,627	54,749	802,376
SCEG	Corporate Security	9230	3,610,265	558,266	4,168,531
SCEG	Corporate Security	9250	(95)	0	(95)
SCEG	Corporate Security	9260	622,579	264,155	886,734
SCEG	Corporate Security	9310	36,992	202	37,194
SCEG	Corporate Security	9350	9,392	2,332	11,724
SCEG	Customer Services & Operational Support	1070	1,348,726	222,752	1,571,478
SCEG	Customer Services & Operational Support	1180	789,711	24,487	814,198
SCEG	Customer Services & Operational Support	1823	107,002	0	107,002
SCEG	Customer Services & Operational Support	1840	342,049	0	342,049
SCEG	Customer Services & Operational Support	1860	11,238	17,378	28,616
SCEG	Customer Services & Operational Support	4081	927,346	87,217	1,014,563
SCEG	Customer Services & Operational Support	4082	507	1,436	1,943
SCEG	Customer Services & Operational Support	4160	64,924	13,766	78,690
SCEG	Customer Services & Operational Support	4171	5,388	5,236	10,624
SCEG	Customer Services & Operational Support	4210	0	18,506	18,506
SCEG	Customer Services & Operational Support	4261	1,398	3,781	5,179
SCEG	Customer Services & Operational Support	4265	38,972	9,197	48,169
SCEG	Customer Services & Operational Support	5370	96	0	96
SCEG	Customer Services & Operational Support	5617	2,455	0	2,455
SCEG	Customer Services & Operational Support	5800	96,831	0	96,831
SCEG	Customer Services & Operational Support	5880	450,822	0	450,822
SCEG	Customer Services & Operational Support	5930	194,451	0	194,451

SCEG	Customer Services & Operational Support	8700	964	0	964
SCEG	Customer Services & Operational Support	8740	228,911	1,651	230,561
SCEG	Customer Services & Operational Support	8850	406	0	406
SCEG	Customer Services & Operational Support	9010	1,192,528	1,630	1,194,158
SCEG	Customer Services & Operational Support	9020	38,203	0	38,203
SCEG	Customer Services & Operational Support	9030	14,883,547	1,223,424	16,106,971
SCEG	Customer Services & Operational Support	9050	2,358,307	94,374	2,452,681
SCEG	Customer Services & Operational Support	9080	61,538	497	62,035
SCEG	Customer Services & Operational Support	9200	1,000,296	99,826	1,100,122
SCEG	Customer Services & Operational Support	9210	438,796	21,018	459,813
SCEG	Customer Services & Operational Support	9230	2,111	9,460	11,572
SCEG	Customer Services & Operational Support	9260	3,292,525	1,169,610	4,462,135
SCEG	Customer Services & Operational Support	9301	27,500	0	27,500
SCEG	Customer Services & Operational Support	9302	1,805	0	1,805
SCEG	Customer Services & Operational Support	9310	1,714	40,242	41,956
SCEG	Customer Services & Operational Support	9350	80,517	2,068	82,585
SCEG	Employee Services	1070	3,194,775	930,808	4,125,583
SCEG	Employee Services	1080	6,574	0	6,574
SCEG	Employee Services	1180	3,708,987	163,075	3,872,062
SCEG	Employee Services	1190	210	0	210
SCEG	Employee Services	1540	11,540	0	11,540
SCEG	Employee Services	1823	13,641	0	13,641
SCEG	Employee Services	1840	136,276	575,812	712,088
SCEG	Employee Services	1860	(88,740)	7,583	(81,157)
SCEG	Employee Services	4081	1,552,158	281,617	1,833,775
SCEG	Employee Services	4082	1,079	2,659	3,738
SCEG	Employee Services	4160	10,365	1,941	12,307
SCEG	Employee Services	4171	4,319	9,156	13,476
SCEG	Employee Services	4210	0	8,075	8,075
SCEG	Employee Services	4261	0	662	662
SCEG	Employee Services	4265	32,749	989,058	1,021,807
SCEG	Employee Services	5000	10,359	0	10,359
SCEG	Employee Services	5010	190	0	190
SCEG	Employee Services	5020	25	0	25
SCEG	Employee Services	5060	2,641	0	2,641
SCEG	Employee Services	5120	458	0	458
SCEG	Employee Services	5140	50	0	50
SCEG	Employee Services	5170	233	0	233
SCEG	Employee Services	5200	80	0	80
SCEG	Employee Services	5240	161,914	0	161,914
SCEG	Employee Services	5370	4,754	0	4,754
SCEG	Employee Services	5390	174	0	174
SCEG	Employee Services	5490	194	0	194
SCEG	Employee Services	5560	55	0	55
SCEG	Employee Services	5620	650	0	650
SCEG	Employee Services	5660	722	0	722

SCEG	Employee Services	5692	96	0	96
SCEG	Employee Services	5700	90	0	90
SCEG	Employee Services	5710	405	0	405
SCEG	Employee Services	5800	75	0	75
SCEG	Employee Services	5830	2,024	0	2,024
SCEG	Employee Services	5850	95	0	95
SCEG	Employee Services	5880	48,603	0	48,603
SCEG	Employee Services	5920	145	0	145
SCEG	Employee Services	5930	8,439	0	8,439
SCEG	Employee Services	5970	35	0	35
SCEG	Employee Services	8410	94	0	94
SCEG	Employee Services	8439	25	0	25
SCEG	Employee Services	8700	70,454	572	71,026
SCEG	Employee Services	8740	72,165	43,751	115,916
SCEG	Employee Services	8790	35	0	35
SCEG	Employee Services	8800	7,355	60	7,415
SCEG	Employee Services	8870	137,734	0	137,734
SCEG	Employee Services	9010	25	0	25
SCEG	Employee Services	9020	40	0	40
SCEG	Employee Services	9030	318,836	31,040	349,876
SCEG	Employee Services	9050	60,586	0	60,586
SCEG	Employee Services	9070	94	0	94
SCEG	Employee Services	9080	8,767	0	8,767
SCEG	Employee Services	9100	33,311	63,771	97,081
SCEG	Employee Services	9120	4,588	0	4,588
SCEG	Employee Services	9200	25,683,087	2,920,601	28,603,687
SCEG	Employee Services	9210	1,249,960	710,817	1,960,778
SCEG	Employee Services	9230	6,311	548,413	554,724
SCEG	Employee Services	9250	189,680	172,998	362,678
SCEG	Employee Services	9260	930,673	1,195,276	2,125,949
SCEG	Employee Services	9302	581	65,233	65,814
SCEG	Employee Services	9310	13,721	1,244,044	1,257,765
SCEG	Employee Services	9350	7,595	2,407	10,002
SCEG	Environmental Services	1070	133,007	35,940	168,947
SCEG	Environmental Services	1080	279,582	0	279,582
SCEG	Environmental Services	1180	59,300	3,951	63,251
SCEG	Environmental Services	1210	3,080	0	3,080
SCEG	Environmental Services	1823	(425)	0	(425)
SCEG	Environmental Services	1840	91,056	0	91,056
SCEG	Environmental Services	1860	52,838	2,804	55,642
SCEG	Environmental Services	4081	128,290	24,405	152,695
SCEG	Environmental Services	4082	1,682	0	1,682
SCEG	Environmental Services	4171	6,382	0	6,382
SCEG	Environmental Services	4210	0	2,986	2,986
SCEG	Environmental Services	4261	10,430	3,844	14,274
SCEG	Environmental Services	4265	26,120	18,220	44,339

SCEG	Environmental Services	5060	3,333	0	3,333
SCEG	Environmental Services	5240	1,667	0	1,667
SCEG	Environmental Services	5390	3,333	0	3,333
SCEG	Environmental Services	5490	556	0	556
SCEG	Environmental Services	5660	27,223	0	27,223
SCEG	Environmental Services	5880	16,112	0	16,112
SCEG	Environmental Services	5920	5,931	0	5,931
SCEG	Environmental Services	7350	1,109,646	0	1,109,646
SCEG	Environmental Services	9200	1,390,321	341,457	1,731,778
SCEG	Environmental Services	9210	415,347	45,693	461,040
SCEG	Environmental Services	9230	1,087,014	105,470	1,192,484
SCEG	Environmental Services	9260	477,456	225,413	702,869
SCEG	Environmental Services	9302	56,416	0	56,416
SCEG	Environmental Services	9310	1,649	0	1,649
SCEG	Environmental Services	9350	311,806	0	311,806
SCEG	Executive Services	1070	1,691,362	53,870	1,745,233
SCEG	Executive Services	1180	0	5,922	5,922
SCEG	Executive Services	1210	10,172	0	10,172
SCEG	Executive Services	1840	212,102	0	212,102
SCEG	Executive Services	1860	4,378	4,203	8,580
SCEG	Executive Services	4081	77,974	139,946	217,921
SCEG	Executive Services	4082	2,141	21,981	24,122
SCEG	Executive Services	4171	7,779	82,528	90,307
SCEG	Executive Services	4210	0	4,476	4,476
SCEG	Executive Services	4261	0	36,775	36,775
SCEG	Executive Services	4264	113,870	116	113,986
SCEG	Executive Services	4265	206,168	670,696	876,864
SCEG	Executive Services	5170	72,045	0	72,045
SCEG	Executive Services	5240	6,592	0	6,592
SCEG	Executive Services	5660	70,483	0	70,483
SCEG	Executive Services	5880	34,778	0	34,778
SCEG	Executive Services	5930	964,845	0	964,845
SCEG	Executive Services	9200	2,923,730	1,980,714	4,904,444
SCEG	Executive Services	9210	538,518	51,168	589,686
SCEG	Executive Services	9230	0	15,383	15,383
SCEG	Executive Services	9260	269,094	556,375	825,469
SCEG	Executive Services	9302	840,971	0	840,971
SCEG	Executive Services	9310	0	4,041	4,041
SCEG	Executive Services	9350	196,764	0	196,764
SCEG	Financial Services	1070	9,605,691	301,075	9,906,766
SCEG	Financial Services	1180	9,537,361	43,803	9,581,163
SCEG	Financial Services	1823	2,317,871	0	2,317,871
SCEG	Financial Services	1832	229	0	229
SCEG	Financial Services	1840	71,427	114,165	185,592
SCEG	Financial Services	1860	153,564	9,676	163,240
SCEG	Financial Services	4081	227,130	4,752,445	4,979,574

SCEG	Financial Services	4082	107,939	7,329	115,268
SCEG	Financial Services	4101	0	0	0
SCEG	Financial Services	4140	1,026,167	11,133,207	12,159,374
SCEG	Financial Services	4160	8,752	47,507	56,259
SCEG	Financial Services	4171	5,298	4,902	10,200
SCEG	Financial Services	4210	0	10,304	10,304
SCEG	Financial Services	4261	(400)	0	(400)
SCEG	Financial Services	4264	64	2,019	2,082
SCEG	Financial Services	4265	102,764	316,794	419,558
SCEG	Financial Services	4300	0	6,296,983	6,296,983
SCEG	Financial Services	4310	9,539	0	9,539
SCEG	Financial Services	4320	0	(6,802)	(6,802)
SCEG	Financial Services	5240	(68,093)	0	(68,093)
SCEG	Financial Services	5370	218	0	218
SCEG	Financial Services	5560	87,167	0	87,167
SCEG	Financial Services	5617	(1,750)	0	(1,750)
SCEG	Financial Services	5880	404	0	404
SCEG	Financial Services	5920	(1,736)	0	(1,736)
SCEG	Financial Services	7350	(639,068)	0	(639,068)
SCEG	Financial Services	8740	3,994	0	3,994
SCEG	Financial Services	9010	0	15	15
SCEG	Financial Services	9030	391,773	54,372	446,144
SCEG	Financial Services	9050	460	0	460
SCEG	Financial Services	9080	252	0	252
SCEG	Financial Services	9200	2,799,912	3,125,984	5,925,896
SCEG	Financial Services	9210	65,749	(125,327)	(59,579)
SCEG	Financial Services	9230	1,868,764	2,283,656	4,152,420
SCEG	Financial Services	9240	(405,940)	382,714	(23,226)
SCEG	Financial Services	9250	1,902,721	(7,303)	1,895,418
SCEG	Financial Services	9260	975,020	1,501,115	2,476,135
SCEG	Financial Services	9280	175	0	175
SCEG	Financial Services	9302	0	252,212	252,212
SCEG	Financial Services	9310	6,056	9,230	15,286
SCEG	Financial Services	9350	519,807	154,463	674,270
SCEG	Gas Control Coordination & Gas Engineering Services	1070	0	22,708	22,708
SCEG	Gas Control Coordination & Gas Engineering Services	1180	779,799	2,496	782,295
SCEG	Gas Control Coordination & Gas Engineering Services	1823	2,884,761	0	2,884,761
SCEG	Gas Control Coordination & Gas Engineering Services	1860	8,791	1,772	10,563
SCEG	Gas Control Coordination & Gas Engineering Services	4081	42,800	46,730	89,530
SCEG	Gas Control Coordination & Gas Engineering Services	4210	0	1,887	1,887
SCEG	Gas Control Coordination & Gas Engineering Services	4265	499	447	946
SCEG	Gas Control Coordination & Gas Engineering Services	8400	68,461	2,585	71,046
SCEG	Gas Control Coordination & Gas Engineering Services	8410	40,660	1,531	42,191
SCEG	Gas Control Coordination & Gas Engineering Services	8432	3,990	0	3,990
SCEG	Gas Control Coordination & Gas Engineering Services	8510	0	235	235
SCEG	Gas Control Coordination & Gas Engineering Services	8610	0	6,534	6,534

SCEG	Gas Control Coordination & Gas Engineering Services	8700	329,314	244,351	573,665
SCEG	Gas Control Coordination & Gas Engineering Services	8740	106,280	369,675	475,955
SCEG	Gas Control Coordination & Gas Engineering Services	8800	27,307	1,075	28,382
SCEG	Gas Control Coordination & Gas Engineering Services	8850	467	734	1,200
SCEG	Gas Control Coordination & Gas Engineering Services	8870	394,360	0	394,360
SCEG	Gas Control Coordination & Gas Engineering Services	9010	351	0	351
SCEG	Gas Control Coordination & Gas Engineering Services	9050	3,251	0	3,251
SCEG	Gas Control Coordination & Gas Engineering Services	9100	272,213	1,931	274,143
SCEG	Gas Control Coordination & Gas Engineering Services	9120	107	1,399	1,506
SCEG	Gas Control Coordination & Gas Engineering Services	9200	259,333	89,717	349,050
SCEG	Gas Control Coordination & Gas Engineering Services	9210	7,059	30,258	37,317
SCEG	Gas Control Coordination & Gas Engineering Services	9230	0	(1,275)	(1,275)
SCEG	Gas Control Coordination & Gas Engineering Services	9260	169,185	265,452	434,636
SCEG	Gas Control Coordination & Gas Engineering Services	9302	145,030	0	145,030
SCEG	Gas Measurement Services	1070	690	6,470	7,160
SCEG	Gas Measurement Services	1180	589,763	711	590,474
SCEG	Gas Measurement Services	1630	88,651	0	88,651
SCEG	Gas Measurement Services	1860	0	505	505
SCEG	Gas Measurement Services	4081	9,176	4,688	13,865
SCEG	Gas Measurement Services	4210	0	538	538
SCEG	Gas Measurement Services	8700	33,346	7,450	40,795
SCEG	Gas Measurement Services	8740	90	617	707
SCEG	Gas Measurement Services	8750	0	393	393
SCEG	Gas Measurement Services	8760	0	552	552
SCEG	Gas Measurement Services	8780	0	410	410
SCEG	Gas Measurement Services	8800	10,908	2,426	13,334
SCEG	Gas Measurement Services	8900	330	0	330
SCEG	Gas Measurement Services	8930	98,256	52,703	150,959
SCEG	Gas Measurement Services	9200	878	60,368	61,246
SCEG	Gas Measurement Services	9210	(9,460)	7,121	(2,339)
SCEG	Gas Measurement Services	9230	0	673	673
SCEG	Gas Measurement Services	9260	33,182	42,182	75,364
SCEG	Gas Measurement Services	9310	0	277,576	277,576
SCEG	Gas Supply and Fuel Procurement	1070	164	10,916	11,080
SCEG	Gas Supply and Fuel Procurement	1180	0	1,200	1,200
SCEG	Gas Supply and Fuel Procurement	1823	113	0	113
SCEG	Gas Supply and Fuel Procurement	1860	0	852	852
SCEG	Gas Supply and Fuel Procurement	4081	26,149	26,851	53,001
SCEG	Gas Supply and Fuel Procurement	4210	0	907	907
SCEG	Gas Supply and Fuel Procurement	4265	136	8,121	8,257
SCEG	Gas Supply and Fuel Procurement	5240	6,737	0	6,737
SCEG	Gas Supply and Fuel Procurement	8700	1	0	1
SCEG	Gas Supply and Fuel Procurement	9200	372,579	376,240	748,820
SCEG	Gas Supply and Fuel Procurement	9210	5,693	112,714	118,407
SCEG	Gas Supply and Fuel Procurement	9260	98,638	141,020	239,658
SCEG	Information Services	1070	12,924,324	934,333	13,858,657

SCEG	Information Services	1080	11,305	0	11,305
SCEG	Information Services	1180	756,932	130,767	887,700
SCEG	Information Services	1190	1,242	0	1,242
SCEG	Information Services	1210	886,599	0	886,599
SCEG	Information Services	1630	178,215	0	178,215
SCEG	Information Services	1822	3,530	0	3,530
SCEG	Information Services	1823	3,276,379	0	3,276,379
SCEG	Information Services	1840	872,806	479,712	1,352,518
SCEG	Information Services	1860	416,245	3,279	419,525
SCEG	Information Services	2270	(580,862)	0	(580,862)
SCEG	Information Services	2430	(305,737)	0	(305,737)
SCEG	Information Services	4081	92,299	19,747	112,046
SCEG	Information Services	4082	8,671	0	8,671
SCEG	Information Services	4140	8,305	120,061	128,366
SCEG	Information Services	4160	36,418	111,211	147,628
SCEG	Information Services	4171	295,944	0	295,944
SCEG	Information Services	4210	0	3,492	3,492
SCEG	Information Services	4261	0	9,693	9,693
SCEG	Information Services	4264	0	2,652	2,652
SCEG	Information Services	4265	218,854	172,147	391,001
SCEG	Information Services	5000	7,836	0	7,836
SCEG	Information Services	5010	10,451	0	10,451
SCEG	Information Services	5060	549,559	0	549,559
SCEG	Information Services	5170	10,885	0	10,885
SCEG	Information Services	5190	53,772	0	53,772
SCEG	Information Services	5200	337,946	0	337,946
SCEG	Information Services	5240	4,892,229	0	4,892,229
SCEG	Information Services	5280	687	0	687
SCEG	Information Services	5290	31,771	0	31,771
SCEG	Information Services	5300	2,228	0	2,228
SCEG	Information Services	5320	1,439,668	0	1,439,668
SCEG	Information Services	5350	4,556	0	4,556
SCEG	Information Services	5370	9,167	0	9,167
SCEG	Information Services	5380	909	0	909
SCEG	Information Services	5390	129,363	0	129,363
SCEG	Information Services	5440	471	0	471
SCEG	Information Services	5460	6,179	0	6,179
SCEG	Information Services	5480	357	0	357
SCEG	Information Services	5490	105,506	0	105,506
SCEG	Information Services	5560	162,280	0	162,280
SCEG	Information Services	5600	11,583	0	11,583
SCEG	Information Services	5611	6,749	0	6,749
SCEG	Information Services	5612	43,000	0	43,000
SCEG	Information Services	5620	188,506	0	188,506
SCEG	Information Services	5630	852	0	852
SCEG	Information Services	5660	199,350	0	199,350

SCEG	Information Services	5680	23,686	0	23,686
SCEG	Information Services	5700	206,583	0	206,583
SCEG	Information Services	5710	3,943	0	3,943
SCEG	Information Services	5730	175,429	0	175,429
SCEG	Information Services	5800	74,034	0	74,034
SCEG	Information Services	5810	1,383	0	1,383
SCEG	Information Services	5820	142,770	0	142,770
SCEG	Information Services	5830	8,132	0	8,132
SCEG	Information Services	5860	12,391	0	12,391
SCEG	Information Services	5880	913,845	0	913,845
SCEG	Information Services	5900	376	0	376
SCEG	Information Services	5920	48,248	0	48,248
SCEG	Information Services	5930	88,020	0	88,020
SCEG	Information Services	5940	49,152	0	49,152
SCEG	Information Services	5950	323	0	323
SCEG	Information Services	5960	9,067	0	9,067
SCEG	Information Services	5970	65,655	0	65,655
SCEG	Information Services	5980	1,505	0	1,505
SCEG	Information Services	8400	838	0	838
SCEG	Information Services	8410	12,155	0	12,155
SCEG	Information Services	8439	9,769	0	9,769
SCEG	Information Services	8700	18,297	0	18,297
SCEG	Information Services	8710	7,762	0	7,762
SCEG	Information Services	8740	86,709	0	86,709
SCEG	Information Services	8750	38,743	0	38,743
SCEG	Information Services	8760	102,897	0	102,897
SCEG	Information Services	8780	15,923	0	15,923
SCEG	Information Services	8790	14,909	0	14,909
SCEG	Information Services	8800	325,807	0	325,807
SCEG	Information Services	8870	2,861	0	2,861
SCEG	Information Services	8900	301	0	301
SCEG	Information Services	8920	2,954	0	2,954
SCEG	Information Services	8930	21,983	0	21,983
SCEG	Information Services	8940	736	0	736
SCEG	Information Services	9010	28,031	0	28,031
SCEG	Information Services	9020	550,599	166,731	717,331
SCEG	Information Services	9030	16,329,927	240,160	16,570,087
SCEG	Information Services	9050	624,893	0	624,893
SCEG	Information Services	9070	1,750	0	1,750
SCEG	Information Services	9080	153,283	0	153,283
SCEG	Information Services	9100	4,717	0	4,717
SCEG	Information Services	9110	2,646	0	2,646
SCEG	Information Services	9120	265,470	0	265,470
SCEG	Information Services	9160	44	335,669	335,713
SCEG	Information Services	9200	552,554	285,081	837,635
SCEG	Information Services	9210	9,096,489	5,367,853	14,464,342

SCEG	Information Services	9230	77,848	76,506	154,354
SCEG	Information Services	9260	326,943	232,182	559,125
SCEG	Information Services	9302	142,236	4,756	146,992
SCEG	Information Services	9310	486,351	39,393	525,745
SCEG	Information Services	9350	2,210,255	30,868	2,241,123
SCEG	Land & Facilities Management	1070	2,935,340	50,688	2,986,028
SCEG	Land & Facilities Management	1080	2,374,315	0	2,374,315
SCEG	Land & Facilities Management	1180	4,344,402	7,738	4,352,140
SCEG	Land & Facilities Management	1190	171,505	0	171,505
SCEG	Land & Facilities Management	1210	261,746	0	261,746
SCEG	Land & Facilities Management	1630	44,974	0	44,974
SCEG	Land & Facilities Management	1823	(2,350)	0	(2,350)
SCEG	Land & Facilities Management	1830	488	0	488
SCEG	Land & Facilities Management	1840	158,092	20,534	178,627
SCEG	Land & Facilities Management	1860	130,590	1,635	132,225
SCEG	Land & Facilities Management	4081	51,798	36,889	88,687
SCEG	Land & Facilities Management	4082	12,516	4,907	17,423
SCEG	Land & Facilities Management	4160	0	150,266	150,266
SCEG	Land & Facilities Management	4171	37,575	18,237	55,812
SCEG	Land & Facilities Management	4210	0	1,741	1,741
SCEG	Land & Facilities Management	4261	0	56,116	56,116
SCEG	Land & Facilities Management	4265	361,595	92,732	454,327
SCEG	Land & Facilities Management	5010	721,602	0	721,602
SCEG	Land & Facilities Management	5060	68,938	0	68,938
SCEG	Land & Facilities Management	5110	213,072	0	213,072
SCEG	Land & Facilities Management	5120	124,117	0	124,117
SCEG	Land & Facilities Management	5130	715	0	715
SCEG	Land & Facilities Management	5140	22,329	0	22,329
SCEG	Land & Facilities Management	5170	25,349	0	25,349
SCEG	Land & Facilities Management	5190	4,475	0	4,475
SCEG	Land & Facilities Management	5240	46,734	0	46,734
SCEG	Land & Facilities Management	5290	469,455	0	469,455
SCEG	Land & Facilities Management	5300	22,826	0	22,826
SCEG	Land & Facilities Management	5310	0	0	0
SCEG	Land & Facilities Management	5320	38,535	0	38,535
SCEG	Land & Facilities Management	5370	8,829	0	8,829
SCEG	Land & Facilities Management	5390	36,977	0	36,977
SCEG	Land & Facilities Management	5430	43,228	0	43,228
SCEG	Land & Facilities Management	5440	50,080	0	50,080
SCEG	Land & Facilities Management	5450	3,282	0	3,282
SCEG	Land & Facilities Management	5460	6,648	0	6,648
SCEG	Land & Facilities Management	5490	64,112	0	64,112
SCEG	Land & Facilities Management	5510	2,889	0	2,889
SCEG	Land & Facilities Management	5520	1,921	0	1,921
SCEG	Land & Facilities Management	5530	19,347	0	19,347
SCEG	Land & Facilities Management	5560	40,143	0	40,143

SCEG	Land & Facilities Management	5620	38	0	38
SCEG	Land & Facilities Management	5630	544	0	544
SCEG	Land & Facilities Management	5660	45,552	0	45,552
SCEG	Land & Facilities Management	5690	27,498	0	27,498
SCEG	Land & Facilities Management	5700	26,078	0	26,078
SCEG	Land & Facilities Management	5710	90,362	0	90,362
SCEG	Land & Facilities Management	5730	2,332	0	2,332
SCEG	Land & Facilities Management	5800	3,328	0	3,328
SCEG	Land & Facilities Management	5820	75	0	75
SCEG	Land & Facilities Management	5830	558	0	558
SCEG	Land & Facilities Management	5860	2,006	0	2,006
SCEG	Land & Facilities Management	5880	52,475	0	52,475
SCEG	Land & Facilities Management	5890	237,849	0	237,849
SCEG	Land & Facilities Management	5900	1,267	0	1,267
SCEG	Land & Facilities Management	5910	2,548	0	2,548
SCEG	Land & Facilities Management	5920	110,117	0	110,117
SCEG	Land & Facilities Management	5930	34,335	0	34,335
SCEG	Land & Facilities Management	5940	2,418	0	2,418
SCEG	Land & Facilities Management	5970	1,037	0	1,037
SCEG	Land & Facilities Management	5980	4,881	0	4,881
SCEG	Land & Facilities Management	8410	138	0	138
SCEG	Land & Facilities Management	8432	15,009	0	15,009
SCEG	Land & Facilities Management	8439	13,379	0	13,379
SCEG	Land & Facilities Management	8750	4,420	0	4,420
SCEG	Land & Facilities Management	8790	481	0	481
SCEG	Land & Facilities Management	8810	225,904	0	225,904
SCEG	Land & Facilities Management	8870	2,010	0	2,010
SCEG	Land & Facilities Management	9020	6,648	0	6,648
SCEG	Land & Facilities Management	9030	10,187	0	10,187
SCEG	Land & Facilities Management	9050	42,009	0	42,009
SCEG	Land & Facilities Management	9080	3,623	0	3,623
SCEG	Land & Facilities Management	9120	4,066	0	4,066
SCEG	Land & Facilities Management	9200	2,887	0	2,887
SCEG	Land & Facilities Management	9210	77,261	25,730	102,991
SCEG	Land & Facilities Management	9260	120,794	207,331	328,125
SCEG	Land & Facilities Management	9302	622	0	622
SCEG	Land & Facilities Management	9310	3,477,705	562,406	4,040,111
SCEG	Land & Facilities Management	9320	716	0	716
SCEG	Land & Facilities Management	9350	2,763,795	2,101,625	4,865,420
SCEG	Legal	1070	3,207,431	54,504	3,261,934
SCEG	Legal	1180	411,733	5,992	417,725
SCEG	Legal	1210	7,937	0	7,937
SCEG	Legal	1823	134,808	0	134,808
SCEG	Legal	1830	21,529	0	21,529
SCEG	Legal	1832	337,265	0	337,265
SCEG	Legal	1860	1,528,533	4,252	1,532,785

SCEG	Legal	4081	109,669	116,537	226,207
SCEG	Legal	4082	113	14	127
SCEG	Legal	4160	6,471	0	6,471
SCEG	Legal	4171	419	49	468
SCEG	Legal	4210	0	4,528	4,528
SCEG	Legal	4265	24,959	170,887	195,846
SCEG	Legal	5240	(76)	0	(76)
SCEG	Legal	5617	1,075	0	1,075
SCEG	Legal	5660	1,130	0	1,130
SCEG	Legal	7350	(3,038)	0	(3,038)
SCEG	Legal	8920	(567)	0	(567)
SCEG	Legal	9030	19	0	19
SCEG	Legal	9040	1,000	0	1,000
SCEG	Legal	9080	6,688	0	6,688
SCEG	Legal	9200	1,275,748	1,624,807	2,900,555
SCEG	Legal	9210	(84,602)	243,080	158,478
SCEG	Legal	9230	2,994,858	1,408,542	4,403,399
SCEG	Legal	9250	1,919,661	226,685	2,146,346
SCEG	Legal	9260	405,639	637,413	1,043,052
SCEG	Legal	9280	(2,511)	0	(2,511)
SCEG	Legal	9302	0	1,892,139	1,892,139
SCEG	Legal	9350	547	13,412	13,959
SCEG	Marketing & Sales	1070	38,832	35,201	74,033
SCEG	Marketing & Sales	1180	0	3,870	3,870
SCEG	Marketing & Sales	1823	116,393	0	116,393
SCEG	Marketing & Sales	1860	0	2,746	2,746
SCEG	Marketing & Sales	4081	50,644	46,174	96,819
SCEG	Marketing & Sales	4082	67,685	1,685	69,371
SCEG	Marketing & Sales	4160	4,239,941	23,680	4,263,621
SCEG	Marketing & Sales	4171	246,591	6,209	252,800
SCEG	Marketing & Sales	4210	0	2,925	2,925
SCEG	Marketing & Sales	4265	1,958,153	22,148	1,980,301
SCEG	Marketing & Sales	5660	761	0	761
SCEG	Marketing & Sales	9070	35	0	35
SCEG	Marketing & Sales	9100	890	0	890
SCEG	Marketing & Sales	9110	5,017	0	5,017
SCEG	Marketing & Sales	9120	175,136	2,065	177,201
SCEG	Marketing & Sales	9130	642	5,975	6,616
SCEG	Marketing & Sales	9160	231,130	0	231,130
SCEG	Marketing & Sales	9200	332,705	661,774	994,478
SCEG	Marketing & Sales	9210	9,770	56,831	66,601
SCEG	Marketing & Sales	9230	16,365	16,107	32,472
SCEG	Marketing & Sales	9260	189,767	303,186	492,952
SCEG	Marketing & Sales	9280	0	617	617
SCEG	Marketing & Sales	9301	0	835	835
SCEG	Marketing & Sales	9302	50,433	44,375	94,808

SCEG	Marketing & Sales	9310	1,774	2,750	4,523
SCEG	Procurement	1070	649,652	36,522	686,174
SCEG	Procurement	1080	6,432	0	6,432
SCEG	Procurement	1180	291,473	4,015	295,488
SCEG	Procurement	1630	292,239	0	292,239
SCEG	Procurement	1860	0	2,849	2,849
SCEG	Procurement	4081	44,690	65,331	110,021
SCEG	Procurement	4082	0	215	215
SCEG	Procurement	4171	0	872	872
SCEG	Procurement	4210	0	3,034	3,034
SCEG	Procurement	4265	220	34,316	34,537
SCEG	Procurement	5240	100	0	100
SCEG	Procurement	5930	2,425	0	2,425
SCEG	Procurement	9120	0	3,021	3,021
SCEG	Procurement	9200	642,960	918,921	1,561,881
SCEG	Procurement	9210	10,175	122,534	132,709
SCEG	Procurement	9230	0	16,496	16,496
SCEG	Procurement	9260	168,126	379,827	547,953
SCEG	Procurement	9302	0	61,830	61,830
SCEG	Procurement	9310	8,524	0	8,524
SCEG	Public Affairs	1070	434,585	38,258	472,844
SCEG	Public Affairs	1180	0	4,206	4,206
SCEG	Public Affairs	1823	3,826	0	3,826
SCEG	Public Affairs	1860	0	2,985	2,985
SCEG	Public Affairs	4081	65,769	21,863	87,632
SCEG	Public Affairs	4082	53,109	35,792	88,900
SCEG	Public Affairs	4171	199,087	134,880	333,968
SCEG	Public Affairs	4210	0	3,179	3,179
SCEG	Public Affairs	4261	3,027,247	39,298	3,066,545
SCEG	Public Affairs	4264	813,075	587,312	1,400,387
SCEG	Public Affairs	4265	1,091,703	276,430	1,368,132
SCEG	Public Affairs	5930	15,042	0	15,042
SCEG	Public Affairs	9100	1,518	465	1,983
SCEG	Public Affairs	9200	910,346	301,248	1,211,595
SCEG	Public Affairs	9210	539,573	286,412	825,985
SCEG	Public Affairs	9260	241,839	226,520	468,359
SCEG	Public Affairs	9280	1,156	0	1,156
SCEG	Public Affairs	9302	0	5,054	5,054
SCEG	Public Affairs	9310	2,635	15,672	18,307
SCEG	Public Affairs	9350	0	54	54
SCEG	Regulatory	1070	436,379	20,248	456,627
SCEG	Regulatory	1180	0	2,226	2,226
SCEG	Regulatory	1823	14,439	0	14,439
SCEG	Regulatory	1860	0	1,580	1,580
SCEG	Regulatory	4081	83,881	10,639	94,520
SCEG	Regulatory	4082	0	392	392

SCEG	Regulatory	4171	0	1,472	1,472
SCEG	Regulatory	4210	0	1,682	1,682
SCEG	Regulatory	4265	3,818	13,062	16,880
SCEG	Regulatory	9200	923,692	152,476	1,076,169
SCEG	Regulatory	9210	30,805	20,141	50,946
SCEG	Regulatory	9230	1,166,088	62,496	1,228,584
SCEG	Regulatory	9260	315,763	116,451	432,214
SCEG	Regulatory	9280	338,133	0	338,133
SCEG	Regulatory	9310	6,654	0	6,654
SCEG	Regulatory	9350	0	449	449
SCEG	Strategic Planning	1070	216,218	30,822	247,040
SCEG	Strategic Planning	1180	530	3,388	3,918
SCEG	Strategic Planning	1840	2,022	0	2,022
SCEG	Strategic Planning	1860	0	2,405	2,405
SCEG	Strategic Planning	4081	104,829	33,267	138,096
SCEG	Strategic Planning	4082	16	568	584
SCEG	Strategic Planning	4171	87	2,017	2,104
SCEG	Strategic Planning	4210	0	2,561	2,561
SCEG	Strategic Planning	4265	1,021	21,300	22,321
SCEG	Strategic Planning	9200	1,492,277	472,725	1,965,003
SCEG	Strategic Planning	9210	292,896	98,957	391,853
SCEG	Strategic Planning	9260	393,869	238,494	632,363
SCEG	Strategic Planning	9280	16,356	0	16,356
SCEG	Strategic Planning	9302	1,424,160	0	1,424,160
SCEG	Strategic Planning	9310	7,511	0	7,511
	Grand Total		243,110,120	76,430,526	319,540,646

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.

Schedule Page: 429 Line No.: 21 Column: d

Amount based on measured usage of assets to include computer resource usage, margin revenues, three-factor formula, number of customers and number of employees.

Schedule	Page No.

Schedule | Page No.

Schedule | Page No.