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

Exact Legal Name of Respondent (Company)	Year/Period of Report
San Diego Gas & Electric 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 San Diego Gas & Electric 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)* 8330 Century Park Court, San Diego, CA 92123	
05 Name of Contact Person Eric Dalton	06 Title of Contact Person Regulatory Reporting Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 488 8th Ave, San Diego, CA 92101	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(858) 503-5130	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Bruce Folkmann	Bruce Folkmann	04/18/2017
02 Title VP, Controller, CFO, CAO, Treasurer		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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)	
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	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	N/A
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	N/A
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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	N/A
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

GENERAL INFORMATION

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

Bruce A. Folkmann, Vice President, Controller, Chief Financial Officer, Chief Accounting Officer, and Treasurer

8330 Century Park Court, San Diego, California 92123

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.

California, April, 6 1905

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.

Electric and Natural Gas Services
State of California

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
San Diego Gas & Electric 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 common stock of San Diego Gas & Electric is owned 100% by Enova Corporation, the common stock of which is owned 100% by Sempra Energy.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.

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	N/A			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Chairman, President and Chief Executive Officer	Jeffrey W. Martin	560,400
2	Chief Development Officer	James P. Avery	375,200
3	Chief Administrative Officer	Lee Schavrien	376,900
4	Chief Information Officer	J. Chris Baker	368,400
5	Chief Regulatory & Risk Officer and General Counsel	Erbin B. Keith	370,200
6	Chief Energy Supply Officer	Scott D. Drury	319,300
7	Chief Energy Delivery Officer	Caroline A. Winn	319,300
8	Chief Financial Officer, Vice President, Treasurer,	Bruce A. Folkmann	320,000
9	Controller & Chief Accounting Officer		
10	Corporate Secretary	Kari E. McCulloch	231,138
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	Steven D. Davis, Director (1)	San Diego, CA
2	Jeffrey W. Martin, Director, Chairman, CEO and President	San Diego, CA
3	G. Joyce Rowland, Director (1)	San Diego, CA
4	Martha B. Wyrsch, Director (1)	San Diego, CA
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10	(1) Does not hold any offices with SDG&E but are officers	
11	of SDG&E's ultimate parent, Sempra Energy.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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		
2	FERC Electric Tariff, Volume No. 11	ER16-445-000
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5	FERC Electric Tariff, Volume No. 11	ER16-1777-000
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8	FERC Electric Tariff, Volume No. 11	ER16-1719-000
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11	FERC Electric Tariff, Volume No. 11	ER16-1604-000
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14	FERC Electric Tariff, Volume No. 11	ER16-546-000
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17	FERC Electric Tariff, Volume No. 11	ER16-550-000
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Name of Respondent San Diego Gas & Electric 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

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					
2	20151201-5347	12/01/2015	ER16-445-000	TO4 Cycle 3 Formula Rate	FERC Electric Tariff, Volume No. 11
3				Annual Informational Filing	
4					
5	20160524-5223	05/24/2016	ER16-1777-000	Cycle 5 Appendix X	FERC Electric Tariff, Volume No. 11
6				Annual Informational Filing	
7					
8	20160517-5096	05/17/2016	ER16-1719-000	Post-Employment Benefits Other	FERC Electric Tariff, Volume No. 11
9				Than Pensions ("PBOP") Filing	
10					
11	20160502-5354	05/02/2016	ER16-1604-000	TO4 Formula Depreciation	FERC Electric Tariff, Volume No. 11
12				Rate Change Filing	
13					
14	20151217-5192	12/17/2015	ER16-546-000	2016 Reliability Service Balancing	FERC Electric Tariff, Volume No. 11
15				Account ("RSBA") Filing	
16					
17	20151217-5199	12/17/2015	ER16-550-000	2016 Transmission Revenue Balancing	FERC Electric Tariff, Volume No. 11
18				Account Adjustment ("TRBAA") and	
19				Transmission Access Charge	
20				Balancing Account Adjustment	
21				("TACBAA") Filing	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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
1		See page 106 and 106a		
2				
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
San Diego Gas & Electric 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. None

2. None

3. None

4. SDG&E has leased additional property at 8680 Balboa Ave., San Diego 92123.

5. Distribution Changes: New circuit C1090 placed in service connected to Jamacha substation. Ciruit 1161 at Border substation energized.

   Transmission Changes: SDG&E placed TL 648 in service (Poway - Rancho Carmel Substation) with a new 445 foot underground section.

   SDG&E placed TL 6913 in service (Poway - Pomerado Substation) with a new 239 foot underground section.

6. During 2016, San Diego Gas & Electric issued commercial paper with an average daily balance of $90.5 million and a maximum outstanding balance of $216.9 million. The year-end balance was $0.

7. None

8. On September 1, 2016, SDG&E employees represented by the International Brotherhood of Electrical Workers (IBEW) Local 465 received a negotiated base rate increase of 3% affecting 1190 employees:

   Total annual base wages for represented employees in 2016 were $1.5 million above 2014 base wages.

   Total annual wages for represented employees including overtime in 2016 were $7.47 million above 2015 wages including overtime.

9. Please refer to the Legal Proceedings section of the Notes to the Financial Statements on page 123.61.

10. None

11. N/A

12. Please refer to the Notes to the Financial Statements beginning on page 123.1.

13. Changes in Officers:

Name	Title	Effective Date
Randall L. Clark	Vice President - Customer Service	Elected, 01/30/2016
Rodger R. Schwecke	Vice President - Gas Transmission	Elected, 03/25/2016
David L. Buczkowski	Vice President - Gas Engineering	Elected, 05/07/2016
Douglas M. Schneider	Vice President - Engineering and System Integrity changed to Vice President - Gas Systems Integrity and Gas Asset Management	Changed, 05/07/2016

David L. Geier	Vice President - Electric Transmission and System Engineering changed to Vice President - Electric Transmission and Engineering	Changed, 06/04/2016
Micheal M. Schneider	Vice President - Operations Support and Chief Environmental Officer changed to Vice President - Operations Support and Sustainability and Chief Environmental Officer	Changed, 06/04/2016
Emily C. Shults	Vice President - Electric and Fuel Procurement changed to Vice President - Energy Procurement	Changed, 06/04/2016
John A. Sowers	Vice President - Electric Distribution Operations changed to Vice President - Electric Distribution	Changed, 06/04/2016
Denita A. Willoughby	Vice President - Supply Management and Logistics changed to Vice President - Supply Management	Changed, 06/04/2016
Randall L. Clark	Vice President - Customer Services	Resigned, 07/01/2016
Scott B. Crider	Vice President - Customer Services	Elected, 07/02/2016
Guillermina Orozco-Mejia	Vice President - Gas Operations	Elected, 08/27/2016
Scott P. Furgerson	Vice President - Gas Operations changed to Vice President- Special Projects	Changed, 08/27/2016
Erbin B. Keith	Senior Vice President, General Counsel and Assistant Secretary changed to Chief Regulatory & Risk Officer & General Counsel and Assistant Secretary	Changed, 09/10/2016
Justin C. Bird	Assistant Secretary	Resigned 11/11/2016
Maria A. Espinosa	Assistant Secretary	Elected, 11/19/2016
Scott P. Furgeson	Vice President - Special Projects	Retired, 11/30/2016

Changes in Directors:

None

There have been no material changes in SDG&E's stock ownership or voting power.

14. N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	16,560,921,577	15,583,922,588
3	Construction Work in Progress (107)	200-201	1,307,453,482	923,122,087
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		17,868,375,059	16,507,044,675
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	5,810,907,185	5,361,217,298
6	Net Utility Plant (Enter Total of line 4 less 5)		12,057,467,874	11,145,827,377
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		12,057,467,874	11,145,827,377
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,946,616	5,946,616
19	(Less) Accum. Prov. for Depr. and Amort. (122)		364,300	364,300
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	182,186,711	140,868,906
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,026,292,476	1,063,117,470
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		74,686,837	51,171,501
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,288,748,340	1,260,740,193
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,666,494	1,246,123
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		500	500
38	Temporary Cash Investments (136)		0	13,200,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		290,548,308	269,828,712
41	Other Accounts Receivable (143)		16,989,164	16,592,327
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,268,739	4,918,499
43	Notes Receivable from Associated Companies (145)		31,230,276	812
44	Accounts Receivable from Assoc. Companies (146)		875,047	1,214,165
45	Fuel Stock (151)	227	2,289,968	5,493,301
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	112,815,264	104,583,010
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	198,409,740	157,498,037

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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		182,186,711	140,868,906
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		239,265	359,925
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		4,618	7,902
57	Prepayments (165)		188,552,215	59,970,279
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		714,901	716,692
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		67,615,000	65,870,000
62	Miscellaneous Current and Accrued Assets (174)		2,294,000	2,304,840
63	Derivative Instrument Assets (175)		132,560,020	104,241,532
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		74,686,837	51,171,501
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)		785,662,493	606,169,251
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		32,459,597	31,553,245
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	200,234,376	291,073,906
72	Other Regulatory Assets (182.3)	232	2,602,605,694	2,888,083,183
73	Prelim. Survey and Investigation Charges (Electric) (183)		117,519	5,035,440
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)		2,015,793	821,264
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	23,389,953	35,199,863
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)		12,069,663	12,292,404
82	Accumulated Deferred Income Taxes (190)	234	316,952,547	276,047,772
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		3,189,845,142	3,540,107,077
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		17,321,723,849	16,552,843,898

Schedule Page: 110   Line No.: 57   Column: c

The 13-month Average Electric Prepayments for 2016 is $41,277,154.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
San Diego Gas & Electric 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	291,458,395	291,458,395
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		591,282,978	591,282,978
7	Other Paid-In Capital (208-211)	253	479,665,369	479,665,369
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	24,605,640	24,605,640
11	Retained Earnings (215, 215.1, 216)	118-119	4,310,137,617	3,892,862,778
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)	-7,479,065	-7,840,314
16	Total Proprietary Capital (lines 2 through 15)		5,640,459,654	5,222,823,566
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,348,934,000	3,989,648,000
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	0	53,650,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		10,660,618	9,710,098
24	Total Long-Term Debt (lines 18 through 23)		4,338,273,382	4,033,587,902
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		588,687,033	631,433,074
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		25,181,795	29,917,817
29	Accumulated Provision for Pensions and Benefits (228.3)		235,792,423	217,194,669
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		176,818,615	83,203,290
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		828,608,319	826,441,431
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,855,088,185	1,788,190,281
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	114,260,980
38	Accounts Payable (232)		496,331,988	418,724,687
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		43,228,051	54,652,222
41	Customer Deposits (235)		76,071,281	71,665,653
42	Taxes Accrued (236)	262-263	2,924,576	2,029,475
43	Interest Accrued (237)		44,771,962	43,773,285
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
San Diego Gas & Electric 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)		4,842,783	4,677,565
48	Miscellaneous Current and Accrued Liabilities (242)		191,563,413	228,176,465
49	Obligations Under Capital Leases-Current (243)		43,031,527	39,832,799
50	Derivative Instrument Liabilities (244)		224,679,048	119,723,777
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		176,818,615	83,203,290
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)		950,626,014	1,014,313,618
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		59,214,600	54,829,188
57	Accumulated Deferred Investment Tax Credits (255)	266-267	16,035,272	18,728,931
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	389,435,074	333,162,681
60	Other Regulatory Liabilities (254)	278	963,593,974	1,366,188,958
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		2,236,989,173	2,031,630,223
64	Accum. Deferred Income Taxes-Other (283)		872,008,521	689,388,550
65	Total Deferred Credits (lines 56 through 64)		4,537,276,614	4,493,928,531
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		17,321,723,849	16,552,843,898

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	4,675,441,554	4,809,317,693		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,813,748,005	2,968,444,719		
5	Maintenance Expenses (402)	320-323	147,675,353	143,626,230		
6	Depreciation Expense (403)	336-337	476,502,991	453,392,042		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	72,759,995	65,809,850		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	15,744	15,744		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		59,819,081	57,699,676		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		381,765			
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	130,167,481	126,821,543		
15	Income Taxes - Federal (409.1)	262-263		11,172,935		
16	- Other (409.1)	262-263	22,002,634	113,208,682		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	627,850,891	570,853,458		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	366,146,724	394,291,215		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,693,659	-2,886,234		
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)		3,982,083,557	4,113,867,430		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		693,357,997	695,450,263		

Name of Respondent San Diego Gas & Electric 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

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
4,175,564,018	4,304,455,432	504,127,587	507,638,955	-4,250,051	-2,776,694	2
						3
2,496,491,349	2,641,565,272	322,195,577	332,176,224	-4,938,921	-5,296,777	4
127,767,903	120,975,470	19,907,450	22,650,760			5
426,807,240	405,451,532	48,222,822	45,773,036	1,472,929	2,167,474	6
						7
61,447,582	56,012,444	11,312,413	9,797,406			8
15,744	15,744					9
59,819,081	57,699,676					10
						11
188,697		193,068				12
						13
114,403,679	111,187,066	15,129,316	14,966,079	634,486	668,398	14
	7,277,252		3,895,683			15
16,395,774	101,466,804	5,606,860	11,741,878			16
570,947,490	503,684,431	56,903,401	67,169,027			17
329,833,167	351,796,872	36,313,557	42,494,343			18
-2,180,730	-2,355,653	-512,929	-530,581			19
						20
						21
						22
						23
						24
3,542,270,642	3,651,183,166	442,644,421	465,145,169	-2,831,506	-2,460,905	25
633,293,376	653,272,266	61,483,166	42,493,786	-1,418,545	-315,789	26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)		693,357,997	695,450,263		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		10,231	4,707		
34	(Less) Expenses of Nonutility Operations (417.1)		-12,707			
35	Nonoperating Rental Income (418)		33,467	71,781		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		5,785,275	25,746,782		
38	Allowance for Other Funds Used During Construction (419.1)		46,452,775	37,153,836		
39	Miscellaneous Nonoperating Income (421)		3,203,447	696,606		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		55,497,902	63,673,712		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		250,048	250,048		
45	Donations (426.1)		7,234,648	7,296,545		
46	Life Insurance (426.2)		-5,578,007	-4,967,255		
47	Penalties (426.3)		1,942	18,337		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,916,220	1,745,671		
49	Other Deductions (426.5)		-682,248	1,691,022		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,142,603	6,034,368		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	647,229	634,674		
53	Income Taxes-Federal (409.2)	262-263		-8,182,199		
54	Income Taxes-Other (409.2)	262-263	230,873	-17,648,091		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	17,722,396	120,444,225		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	19,449,488	98,959,713		
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)		-848,990	-3,711,104		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		53,204,289	61,350,448		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		176,236,940	188,053,798		
63	Amort. of Debt Disc. and Expense (428)		3,332,177	3,313,278		
64	Amortization of Loss on Reaquired Debt (428.1)		3,264,017	2,807,389		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		8,883			
68	Other Interest Expense (431)		9,283,327	7,109,923		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		15,132,370	13,701,644		
70	Net Interest Charges (Total of lines 62 thru 69)		176,992,974	187,582,744		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		569,569,312	569,217,967		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)			-26,107,334		
75	Net Extraordinary Items (Total of line 73 less line 74)			26,107,334		
76	Income Taxes-Federal and Other (409.3)	262-263		10,637,694		
77	Extraordinary Items After Taxes (line 75 less line 76)			15,469,640		
78	Net Income (Total of line 71 and 77)		569,569,312	584,687,607		

Schedule Page: 114 Line No.: 2 Column: c

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 2 Column: d

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 2 Column: k

Eliminates interdepartmental transfers	$ (6,284,095)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	2,034,044
	$ (4,250,051)

Schedule Page: 114 Line No.: 2 Column: l

Eliminates interdepartmental transfers	$ (7,341,709)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	4,565,015
	$ (2,776,694)

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

Total Operating Expenses excludes amounts associated with interdepartmental transfers.

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

Total Operating Expenses excludes amounts associated with interdepartmental transfers.

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

Eliminates interdepartmental transfers	$ (6,284,096)
Citizens Energy Corporation Operating Expenses	1,345,175
	$ (4,938,921)

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

Eliminates interdepartmental transfers	$ (7,341,709)
Citizens Energy Corporation Operating Expenses	2,044,932
	$ (5,296,777)

Schedule Page: 114 Line No.: 6 Column: k

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	(1,364,031)
	$ 1,472,929

Schedule Page: 114 Line No.: 6 Column: l

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,961
Other	(669,487)
	$ 2,167,474

Schedule Page: 114 Line No.: 14 Column: k

Citizens Energy Corporation Property Tax	$ 604,652
Citizens Energy Corporation Payroll Tax	29,834
	$ 634,486

Schedule Page: 114 Line No.: 14 Column: l

Citizens Energy Corporation Property Tax	$ 630,018
Citizens Energy Corporation Payroll Tax	38,380
	$ 668,398

Schedule Page: 114 Line No.: 38 Column: c

Modification of the Alloance for Funds Used During Construction Rate

San Diego Gas and Electric (SDG&E) received FERC approval to modify its existing Allowance for Funds Used During Construction (AFUDC) rate by excluding certain short-term debt associated with the financing of the net revenue under-collections recorded in its regulatory balancing and memo accounts.

Schedule Page: 114 Line No.: 69 Column: c

Modification of the Alloance for Funds Used During Construction Rate

San Diego Gas and Electric (SDG&E) received FERC approval to modify its existing Allowance for Funds Used During Construction (AFUDC) rate by excluding certain short-term debt associated with the financing of the net revenue under-collections recorded in its regulatory balancing and memo accounts.

Schedule Page: 114 Line No.: 76 Column: d

The taxes relating to the extraordinary deductions of $26,107,334 are allocated as follows:

- State taxes: Account 409.3 = $2,307,888
- Federal Taxes: Account 409.3 = $8,329,806

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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		3,892,862,778	3,608,175,171
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	ASU 2016-09 Stock Comp Adjustment		22,705,527	
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		22,705,527	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		569,569,312	584,687,607
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
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			-175,000,000	(300,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-175,000,000	(300,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		4,310,137,617	3,892,862,778
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)
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)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		4,310,137,617	3,892,862,778
	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)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Schedule Page: 118 Line No.: 5 Column: c

Adjustment due to ASU 2016-09 Stock Compensation Adoption. See Note 2. "New Accounting Standards" for more information.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	569,569,312	584,687,607
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	476,502,991	453,392,042
5	Amortization of Utility Acquisition Adjustment Property Losses.		
6	Amortization of Unrecovered Plant and Regulatory Study Costs	132,594,820	123,525,270
7	Impairment of SONGS Asset		-26,107,334
8	Deferred Income Taxes (Net)	259,977,075	198,046,752
9	Investment Tax Credit Adjustment (Net)	-2,693,659	-2,886,234
10	Net (Increase) Decrease in Receivables	-23,172,075	-26,826,375
11	Net (Increase) Decrease in Inventory	-4,904,978	-1,930,128
12	Net (Increase) Decrease in Allowances Inventory	-57,675,353	-117,347,728
13	Net Increase (Decrease) in Payables and Accrued Expenses	3,353,668	-1,242,900
14	Net (Increase) Decrease in Other Regulatory Assets	613,871,664	279,856,589
15	Net Increase (Decrease) in Other Regulatory Liabilities	-413,530,027	-17,013,093
16	(Less) Allowance for Other Funds Used During Construction	46,452,775	37,153,836
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-119,080,971	166,678,998
19	Net Increase (Decrease) in Accrued Interest and Taxes	2,060,789	-165,545,528
20			
21	Other - Net	-94,299,532	193,030,198
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,296,120,949	1,603,164,300
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,439,047,600	-1,169,605,307
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-46,452,775	-37,153,836
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,392,594,825	-1,132,451,471
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-30,916,000	-813
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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			
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	Other: Decommissioning Trust Fund Purchase	-1,033,971,880	-527,201,015
54	Decommissioning Trust Fund Sales	1,133,846,875	577,478,782
55	Increase/(Decrease) in Customer Advances for Construction	3,235,232	17,008,322
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,320,400,598	-1,065,166,195
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	498,375,000	443,625,698
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Other: LTD Issuance cost	-3,250,000	-2,277,972
66	Net Increase in Short-Term Debt (c)	-114,260,980	-131,311,081
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	380,864,020	310,036,645
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-194,364,000	-536,757,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-175,000,000	-300,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	11,500,020	-526,720,355
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-12,779,629	11,277,750
87			
88	Cash and Cash Equivalents at Beginning of Period	14,446,623	3,168,873
89			
90	Cash and Cash Equivalents at End of period	1,666,994	14,446,623

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.

A. Notes for Statement of Cash Flows:

Supplemental Disclosure of Cash Flow Information:	12/31/2016
Income tax payments (refunds), net	$ 136,912,581
Interest payments, net of amounts capitalized	$ 167,499,337
Reconciliation of cash and cash equivalents at Dec 31, 2016:	
Account 131 Cash	$ 1,666,494
Account 135 Working Funds	500
Account 136 Temporary Cash Investments	0
	$ 1,666,994

Supplemental Disclosure of Non-Cash Investing Activities:	
Increase (Decrease) in capital lease obligation for investments in property, plant and equipment	$ 0
Accrued capital expenditures	$ 225,492,000

B. Basis of Presentation and Notes to Financial Statements

Beginning on page 123.3 are excerpts from Sempra Energy's (Sempra or the parent) Annual Report on Form 10-K for the period ending December 31, 2016, as filed with the Securities and Exchange Commission (SEC) on February 28, 2017. The following disclosures contain information in accordance with SEC requirements.

These financial statements, included on pages 110 through 122b of this report, were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in the applicable Uniform System of Accounts and published accounting releases. Such requirements and published accounting releases constitute a comprehensive basis of accounting other than Accounting Principles Generally Accepted in the United States of America (GAAP). The principal differences of this basis of accounting from GAAP include, but are not necessarily limited to, the accounting for and classification of:

- Certain deferred income taxes and regulatory assets and liabilities
- Certain assets and liabilities between current and non-current
- Certain cost of removal obligations and property revenues
- Classification of interest and penalties associated with income taxes
- Electricity sales for resale and purchase power expenses
- Certain revenues net of related costs
- Capital lease treatment of certain contracts, which are consolidated as variable interest entities (VIE) for GAAP purposes
- Certain plant in service, accumulated depreciation, and regulatory assets

Accordingly, certain Notes to the Financial Statements are not reflective of San Diego Gas & Electric's (SDG&E) Financial Statements contained herein, which have been prepared on a stand alone basis, which exclude consolidation with Otay Mesa Energy Center LLC's (OMEC) Financial Statements, and which include capital lease treatment for the OMEC power purchase agreement. We provide further detail in Note C.

Due to the differences between FERC and SEC reporting requirements as mentioned above, certain amounts disclosed in Notes 1-12 may not agree to balances in the FERC financial statements.

C. Other FERC Related Disclosures

FERC Capital Leases

The following agreement is accounted for as a capital lease under FERC accounting requirements and consolidated as a variable interest entity under GAAP requirements.

Otay Mesa Energy Center, LLC Power Purchase Agreement

We have an agreement through 2019 to purchase power generated at OMEC, a 573-megawatt generating facility that began commercial operation in October 2009. We supply all of the natural gas to fuel the power plant, and we purchase its full electric generation output. As of December 31, 2016, the capital lease was valued at $595 million, and the corresponding capital lease obligation with a 10-year term was valued at $392 million.

At December 31,2016, the future minimum lease payments and present value of the net minimum lease payments under these capital leases were as follows:

(Dollars in millions)		
2017		67
2018		67
2019		331
Total minimum lease payments(1)		465
Less: interest(2)		(73)
Present value of net minimum lease payments(3)	$	392

(1) *This amount will be recorded over the life of the lease as Cost of Electric Fuel and Purchased Power on our Statement of Operations. This expense will receive ratemaking treatment consistent with purchased-power costs.*

(2) *Amount necessary to reduce net minimum lease payments to present value at the inception of the leases.*

(3) *Includes $38 million in Current Portion of Capital Lease Obligation and $354 million in Long-Term Capital Lease Obligation on the Balance Sheet at December 31, 2016.*

The annual amortization charge for the OMEC power purchase agreement was $35 million for 2016 and $33 million for 2015.

Modifications to the 2015 Reported Footnotes

During the current period, certain modifications were made to the previously reported 2015 footnotes to reflect the impacts of the OMEC capital lease described above. Previously, the OMEC capital lease had been excluded from the footnote disclosures. The financial statements from page 110 – 122 did not change as the OMEC capital lease had been included therein. The following modifications were made within the footnotes:

MODIFICATIONS TO THE FOLLOWING 2015 FOOTNOTES

(Dollars in millions)

	As Reported in 2015	Modification	Revised 2015 Amount
Note 1. Property, Plant and Equipment by Major Functional Category (Table)			
Electric Generation	$ 1,326	$ 596	$ 1,922
Note 1. Accumulated Depreciation (Table)			
Electric	$ 3,330	$ 168	$ 3,498
Note 3. Long-Term Debt (Table)			
Purchased-power agreements	$ 243	$ 427	$ 670
Current portion long-term debt	$ 40	$ 35	$ 75
Unamortized debt issuance costs	$ 33	$ 2	$ 31
Note 8. Fair Value of Financial Instruments (Footnote Only)			
Unamortized discount and debt issuance costs	$ 43	$ 2	$ 41
Capital lease obligations	$ 244	$ 427	$ 671
Note 12. Commitments and Contingencies (Text only)			
Capital Leases - Number of Power Purchase Agreements	4	1	5
Amortization charge for power purchase agreements 2014	$ 3	$ 30	$ 33
Amortization charge for power purchase agreements 2015	$ 4	$ 32	$ 36

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

BASIS OF PRESENTATION

This is a report of San Diego Gas & Electric Company (SDG&E). SDG&E's common stock is wholly owned by Enova Corporation, which is a wholly owned subsidiary of Sempra Energy. Sempra Energy also indirectly owns all of the common stock of Southern California Gas Company (SoCalGas). References in this report to "we" and "our" are to SDG&E, unless otherwise indicated by the context.

Regulated Operations

SDG&E prepares its financial statements in accordance with the provisions of accounting principles generally accepted in the United States of America (U.S. GAAP) governing rate-regulated operations, as we discuss below in "Effects of Regulation."

Use of Estimates in the Preparation of the Financial Statements

We have prepared our Financial Statements in conformity with U.S. GAAP. This requires us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes, including the disclosure of contingent assets and liabilities at the date of the financial statements. Although we believe the estimates and assumptions are reasonable, actual amounts ultimately may differ significantly from those estimates.

Subsequent Events

We evaluated events and transactions that occurred after December 31, 2016 through February 28th, 2017, the date the financial statements were issued, and in the opinion of management, the accompanying statements reflect all adjustments and disclosures necessary for a fair presentation.

EFFECTS OF REGULATION

Our accounting policies conform with U.S. GAAP for rate-regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

We prepare our financial statements in accordance with U.S. GAAP provisions governing rate-regulated operations. Under these provisions, a regulated utility records regulatory assets, which are generally costs that would otherwise be charged to expense, if it is probable that, through the ratemaking process, the utility will recover those assets from customers. To the extent that recovery is no longer probable, the related regulatory assets are written off. Regulatory liabilities generally represent amounts collected from customers in advance of the actual expenditure by the utility. If the actual expenditures are less than amounts previously collected from ratepayers, the excess would be refunded to customers, generally by reducing future rates. Regulatory liabilities may also arise from other transactions such as unrealized gains on fixed price contracts and other derivatives or certain deferred income tax benefits that are passed through to customers in future rates. In addition, we record regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other transaction of net allowable costs be given to customers over future periods.

Determining probability of recovery requires significant judgment by management and may include, but is not limited to, consideration of:

- the nature of the event giving rise to the assessment;
- existing statutes and regulatory code;
- legal precedents;
- regulatory principles and analogous regulatory actions;
- testimony presented in regulatory hearings;
- proposed regulatory decisions;
- final regulatory orders;
- a commission-authorized mechanism established for the accumulation of costs;
- status of applications for rehearings or state court appeals;
- specific approval from a commission; and
- historical expense

We provide information concerning regulatory assets and liabilities in Notes 10 and 11.

FAIR VALUE MEASUREMENTS

We measure certain assets and liabilities at fair value on a recurring basis, primarily nuclear decommissioning and benefit plan trust assets and derivatives. We also measure certain assets at fair value on a non-recurring basis in certain circumstances. These assets can include goodwill, intangible assets, equity method investments and other long-lived assets.

"Fair value" is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

A fair value measurement reflects the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risk inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model. Also, we consider an issuer's credit standing when measuring its liabilities at fair value.

We establish a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 financial instruments primarily consist of listed equities, U.S. government treasury securities, primarily in the nuclear decommissioning and benefit plan trusts, and exchange-traded derivatives.

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including:

- quoted forward prices for commodities
- time value
- current market and contractual prices for the underlying instruments
- volatility factors
- other relevant economic measures

Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Our financial instruments in this category include domestic corporate bonds, municipal bonds and other foreign bonds, primarily in the Nuclear Decommissioning Trusts and in our pension and postretirement benefit plans, and non-exchange-traded derivatives such as interest rate instruments and over-the-counter forwards and options.

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value from the perspective of a market participant. Our Level 3 financial instruments consist of congestion revenue rights (CRRs) and fixed-price electricity positions at SDG&E.

CASH AND CASH EQUIVALENTS

Cash equivalents are highly liquid investments with maturities of three months or less at the date of purchase.

COLLECTION ALLOWANCES

We record allowances for the collection of trade and other accounts and notes receivable, which include allowances for doubtful customer accounts and for other receivables. We show the changes in these allowances in the table below:

COLLECTION ALLOWANCES
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
Allowances for collection of receivables at January 1	$ 9	$ 7	$ 5
Provisions for uncollectible accounts	6	7	7
Write-offs of uncollectible accounts	(7)	(5)	(5)
Allowances for collection of receivables at December 31	$ 8	$ 9	$ 7

We evaluate accounts receivable collectability using a combination of factors, including past due status based on contractual terms, trends in write-offs, the age of the receivable, counterparty creditworthiness, economic conditions and specific events, such as bankruptcies. Adjustments to the allowance for doubtful accounts are made when necessary based on the results of analysis, the aging of receivables, and historical and industry trends.

We write off accounts receivable in the period in which we deem the receivable to be uncollectible. We record recoveries of accounts receivable previously written off when it is known that they will be received.

INVENTORIES

We value natural gas inventory using the last-in first-out (LIFO) method. As inventories are sold, differences between the LIFO valuation and the estimated replacement cost are reflected in customer rates. These differences are generally temporary, but may become permanent if the natural gas inventory withdrawn from storage during the year is not replaced by year end. We generally value materials and supplies at the lower of average cost or net realizable value.

The components of inventories by segment are as follows:

INVENTORY BALANCES AT DECEMBER 31
(Dollars in millions)

	Natural gas		Materials and supplies		Total	
	2016	2015	2016	2015	2016	2015
SDG&E	$ 2	$ 6	$ 75	$ 66	$ 77	$ 72

INCOME TAXES

Income tax expense includes current and deferred income taxes from operations during the year. We record deferred income taxes for temporary differences between the book and the tax basis of assets and liabilities. Investment tax credits from prior years are amortized to income over the estimated service lives of the properties as required by the CPUC.

Under the regulatory accounting treatment required for flow-through temporary differences, as discussed in Note 4, we recognize

- regulatory assets to offset deferred tax liabilities if it is probable that the amounts will be recovered from customers; and
- regulatory liabilities to offset deferred tax assets if it is probable that the amounts will be returned to customers.

When there are uncertainties related to potential income tax benefits, in order to qualify for recognition, the position we take has to have at least a "more likely than not" chance of being sustained (based on the position's technical merits) upon challenge by the respective authorities. The term "more likely than not" means a likelihood of more than 50 percent. Otherwise, we may not recognize any of the potential tax benefit associated with the position. We recognize a benefit for a tax position that meets the "more likely than not" criterion at the largest amount of tax benefit that is greater than 50 percent likely of being realized upon its effective resolution.

Unrecognized tax benefits involve management's judgment regarding the likelihood of the benefit being sustained. The final resolution of uncertain tax positions could result in adjustments to recorded amounts and may affect our effective tax rate.

We provide additional information about income taxes in Note 4.

GREENHOUSE GAS (GHG) ALLOWANCES

SDG&E is required by California Assembly Bill 32 to acquire GHG allowances for every metric ton of carbon dioxide equivalent emitted into the atmosphere during electric generation and natural gas transportation. Many GHG allowances are allocated to us at no cost on behalf of our customers. We record purchased and allocated GHG allowances at the lower of weighted average cost or market, and include them in Other Current Assets and in Sundry on the Balance Sheet based on the dates on which they are required to be surrendered. We measure the compliance obligation, which is based on emissions, at the carrying value of allowances held plus the fair value of additional allowances necessary to satisfy the obligation. We balance costs and revenues associated with the GHG program through regulatory balancing accounts on the Balance Sheet. We include the obligation in Other Current Liabilities and Deferred Credits and Other on the Balance Sheet based on the dates on which the allowances will be surrendered. We remove the assets and liabilities from the balance sheets as the allowances are surrendered.

GHG allowances and obligations on our Balance Sheet are as follows:

GHG ALLOWANCES AND OBLIGATIONS AT DECEMBER 31
(Dollars in millions)

	2016	2015
Assets:		
Current	$ 16	$ 17
Noncurrent	182	141
Total assets	$ 198	$ 158
Liabilities:		
Current	$ 16	$ 17
Noncurrent	72	34
Total liabilities	$ 88	$ 51

RENEWABLE ENERGY CERTIFICATES (RECs)

RECs are energy rights established by governmental agencies for the environmental and social promotion of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source in certain markets.

Retail sellers of electricity obtain RECs through renewable power purchase agreements, internal generation or separate purchases in the market to comply with renewable portfolio standards established by the governmental agencies. RECs provide documentation for the generation of a unit of renewable energy that is used to verify compliance with renewable portfolio standards. The cost of RECs at SDG&E is recorded in Cost of Electric Fuel and Purchased Power, which is recoverable in rates, on the Statement of Operations.

PROPERTY, PLANT, AND EQUIPMENT (PP&E)

PP&E primarily represents the buildings, equipment and other facilities used to provide natural gas and electric utility services, including construction work in progress.

Our plant costs include

- labor
- materials and contract services
- expenditures for replacements parts incurred during a major maintenance outage of a generating plant

In addition, the cost of utility plant includes AFUDC. We discuss AFUDC below. The cost of non-utility plant includes capitalized interest.

Maintenance costs are expensed as incurred. The cost of most retired depreciable utility plant assets less salvage value is charged to accumulated depreciation.

We discuss collateralized assets as security for loans in Note 3.

PROPERTY, PLANT AND EQUIPMENT BY MAJOR FUNCTIONAL CATEGORY

(Dollars in millions)

	Property, plant and equipment at December 31,		Depreciation rates for years ended December 31,		
	2016	2015	2016	2015	2014
Natural gas operations	$ 1,897	$ 1,642	2.40%	2.52%	2.72%
Electric distribution	6,497	6,151	3.86	3.79	3.79
Electric transmission(1)	5,152	4,870	2.66	2.62	2.59
Electric generation(2)	1,937	1,922	4	3.89	3.86
Other electric(3)	1,059	981	5.66	5.73	7.09
Construction work in progress(1)	1,307	923	NA	NA	NA
Total SDG&E	17,849	16,489			

(1) At December 31, 2016, includes $388 million in electric transmission assets and $46 million in construction work in progress related to SDG&E's 91-percent interest in the Southwest Powerlink (SWPL) transmission line, jointly owned by SDG&E with other utilities. SDG&E, and each of the other owners, holds its undivided interest as a tenant in common in the property. Each owner is responsible for its share of the project and participates in decisions concerning operations and capital expenditures.
(2) Includes capital lease assets of $853 million at both December 31, 2016 and 2015, primarily related to variable interest entities of which SDG&E is not the primary beneficiary. The 2015 reported amount changed from the prior year to include OMEC as a capital lease.
(3) Includes capital lease assets of $21 million and $20 million at December 31, 2016 and 2015, respectively.

Depreciation expense is computed using the straight-line method over the asset's estimated original composite useful life, the CPUC-prescribed period or the remaining term of the site leases, whichever is shortest.

Depreciation expense on our Statement of Operations is as follows:

DEPRECIATION EXPENSE *(Dollars in millions)*			
	Years ended December 31,		
	2016	2015	2014
SDG&E	$ 548	$ 518	$ 485

Accumulated depreciation on our Balance Sheet is as follows:

ACCUMULATED DEPRECIATION *(Dollars in millions)*		
	December 31,	
	2016	2015
Accumulated depreciation:		
Electric(1)	$ 3,841	$ 3,498
Natural gas	721	690
Total SDG&E	4,562	4,188

(1) Includes accumulated depreciation for assets under capital lease of $242 million and $202 million at December 31, 2016 and 2015, respectively. Includes $229 million at December 31, 2016 related to SDG&E's 91-percent interest in the SWPL transmission line, jointly owned by SDG&E and other utilities. The 2015 reported amount changed from the prior year include OMEC as a capital lease.

We finance our construction projects with debt and equity funds. The CPUC and the FERC allow the recovery of the cost of these funds by the capitalization of AFUDC, calculated using rates authorized by the CPUC and the FERC, as a cost component of PP&E. We earn a return on the capitalized AFUDC after the utility property is placed in service and recover the AFUDC from our customers over the expected useful lives of the assets. We also capitalize certain interest costs.

Interest capitalized and AFUDC are as follows:

CAPITALIZED FINANCING COSTS *(Dollars in millions)*			
	Years ended December 31,		
	2016	2015	2014
SDG&E	$ 62	$ 51	$ 52

LONG-LIVED ASSETS

We tested long-lived assets for recoverability whenever events or changes in circumstances have occurred that may affect the recoverability or the estimated useful lives of long-lived assets. Long-lived assets include intangible assets subject to amortization, but do not include investments in unconsolidated subsidiaries. Events or changes in circumstances that indicate that the carrying amount of a long-lived asset may not be recoverable may include

- significant decreases in the market price of an asset
- a significant adverse change in the extent or manner in which we use an asset or in its physical condition
- a significant adverse change in legal or regulatory factors or in the business climate that could affect the value of an asset

- a current period operating or cash flow loss combined with a history of operating or cash flow losses or a projection of continuing losses associated with the use of a long-lived asset
- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life

A long-lived asset may be impaired when the estimated future undiscounted cash flows are less than the carrying amount of the asset. If that comparison indicates that the asset's carrying value may not be recoverable, the impairment is measured based on the difference between the carrying amount and the fair value of the asset. This evaluation is performed at the lowest level for which separately identifiable cash flows exist.

ASSET RETIREMENT OBLIGATIONS

For tangible long-lived assets, we record asset retirement obligations for the present value of liabilities of future costs expected to be incurred when assets are retired from service, if the retirement process is legally required and if a reasonable estimate of fair value can be made. We also record a liability if a legal obligation to perform an asset retirement exists and can be reasonably estimated, but performance is conditional upon a future event. We record the estimated retirement cost over the life of the related asset by depreciating the asset retirement cost (measured as the present value of the obligation at the time of the asset's acquisition), and accreting the obligation until the liability is settled. Rate-regulated entities record regulatory assets or liabilities as a result of the timing difference between the recognition of costs in accordance with U.S. GAAP and costs recovered through the rate-making process.

We have recorded asset retirement obligations related to various assets, including:

- fuel and storage tanks
- natural gas transmission systems
- natural gas distribution systems
- hazardous waste storage facilities
- asbestos-containing construction materials
- decommissioning of nuclear power facilities
- electric distribution and transmission systems
- site restoration of a former power plant
- power generation plant (natural gas)

The changes in asset retirement obligations are as follows:

CHANGES IN ASSET RETIREMENT OBLIGATIONS
(Dollars in millions)

	2016	2015
Balance as of January 1(1)	$ 828	$ 873
Accretion expense	38	40
Liabilities incurred and acquired	—	—
Deconsolidation and reclassification	—	—
Payments	(46)	(79)
Revisions(2)	10	(6)
Balance at December 31(1)	$ 830	$ 828

(1) The current portions of the obligations are included in Other Current Liabilities on the Balance Sheet.

(2) *The revisions are primarily related to revised estimates of cash flows and, additionally in 2016, to changes in the cost of removal rates primarily for natural gas assets based on updated cost studies approved in the final decision in the 2016 General Rate Case. We discuss the 2016 General Rate Case in Note 11.*

CONTINGENCIES

We accrue losses for the estimated impacts of various conditions, situations or circumstances involving uncertain outcomes. For loss contingencies, we accrue the loss if an event has occurred on or before the balance sheet date and:

- information available through the date we file our financial statements indicates it is probable that a loss has been incurred, given the likelihood of uncertain future events; and
- the amount of the loss can be reasonably estimated.

We do not accrue contingencies that might result in gains. We continuously assess contingencies for litigation claims, environmental remediation and other events.

LEGAL FEES

Legal fees that are associated with a past event for which a liability has been recorded are accrued when it is probable that fees also will be incurred and amounts are estimable.

COMPREHENSIVE INCOME

Comprehensive income includes all changes in the equity of a business enterprise (except those resulting from investments by ownersand distributions to owners), including:

- certain hedging activities
- changes in unamortized net actuarial gain or loss and prior service cost related to pension and other postretirement benefits plans
- unrealized gains or losses on available-for-sale securities

The Statement of Comprehensive Income shows the changes in the components of other comprehensive income (loss) (OCI). The following tables present the changes in AOCI by component and amounts reclassified out of AOCI to net income for the years ended December 31:

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) BY COMPONENT(1)
(Dollars in millions)

	Pension and other postretirement benefits	Total accumulated other comprehensive income (loss)
Balance as of December 31, 2013	$ (9)	$ (9)
OCI before reclassifications	(5)	(5)
Amounts reclassified from AOCI	2	2
Net OCI	(3)	(3)
Balance as of December 31, 2014	(12)	(12)
OCI before reclassifications	3	3

Amounts reclassified from AOCI	1	1
Net OCI	4	4
Balance as of December 31, 2015	(8)	(8)
OCI before reclassifications	(1)	(1)
Amounts reclassified from AOCI	1	1
Net OCI	—	—
Balance as of December 31, 2016	$ (8)	$ (8)

RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

(Dollars in millions)

Details about accumulated other comprehensive income (loss) components	Amounts reclassified from accumulated other comprehensive income (loss)			Affected line item on Consolidated Statements of Operations
	Years ended December 31,			
	2016	2015	2014	
Pension and other postretirement benefits:				
Amortization of actuarial loss	$ 1	$ 1	$ 3	See note (1) below
	—	—	(1)	Income Tax Expense
Net of income tax	$ 1	$ 1	$ 2	
Total reclassifications for the period, net of tax	$ 1	$ 1	$ 2	

(1) Amounts are included in the computation of net periodic benefit cost (see "Net Periodic Benefit Cost" in Note 5).

REVENUES

We generate revenues primarily from deliveries to our customers of electricity and natural gas and from related services. We record these revenues following the accrual method and recognize them upon delivery and performance. As described below, recorded revenues include those authorized by the CPUC to support our operations ("decoupled revenue"), as well as commodity costs that are passed through to core gas customers and electric customers:

- Decoupled revenue - The regulatory framework permits SDG&E to recover authorized revenue based on estimated annual demand forecasts approved in regular proceedings before the CPUC. Any difference between actual demand and the annual demand approved in the proceedings is recovered or refunded in authorized revenue in the subsequent year. This design, commonly known as "decoupling," is intended to minimize any impact on earnings due to variability in volumetric demand for electricity and natural gas.
- Commodity costs - The regulatory framework authorizes SDG&E to recover the actual cost of natural gas procured and delivered to its core customers in rates substantially as incurred. Actual electricity procurement costs are recovered as power is delivered, or to the extent actual amounts vary from forecasts, generally recovered or refunded within the subsequent year. SDG&E may also record revenue from CPUC-approved incentive awards, some of which require approval by the CPUC prior to being recognized. SDG&E bids and self-schedules its generation into the California Independent System Operator (ISO) energy market on a day-ahead and real-time basis and self-schedules power to serve the demand of its customers. Generally, SDG&E is a net purchaser of power. The California ISO settles SDG&E costs and revenues on an hourly and real-time net basis.

OPERATION AND MAINTENANCE EXPENSES

Operation and Maintenance includes operating and maintenance costs, and general and administrative costs, consisting primarily of personnel costs, purchased materials and services, litigation expense and rent.

TRANSACTION WITH AFFILIATES

Amounts due fromand to unconsolidated affiliates at SDG&E are as follows:

AMOUNTS DUE FROM (TO) UNCONSOLIDATED AFFILIATES
(Dollars in millions)

	December 31, 2016	December 31, 2015
SDG&E:		
Sempra Energy(1)	$ 3	$ —
Various affiliates	1	1
Total due from various unconsolidated affiliates – current	$ 4	$ 1
Sempra Energy	$ —	$ (34)
SoCalGas	(8)	(13)
Various affiliates	(7)	(8)
Total due to unconsolidated affiliates – current	$ (15)	$ (55)
Income taxes due from Sempra Energy(2)	$ 159	$ 28

(1) At December 31, 2016, net receivable included outstanding advances to Sempra Energy of $31 million at an interest rate of 0.68%.
(2) SDG&E is included in the consolidated income tax return of Sempra Energy and is allocated income tax expense from Sempra Energy in an amount equal to that which would result from having always filed a separate return.

Revenues and cost of sales from unconsolidated affiliates are as follows:

REVENUES AND COST OF SALES FROM CONSOLIDATED AFFILIATES
(Dollars in millions)

	Years ended December 31, 2016	2015	2014
Revenues	$ 7	$ 10	$ 13
Cost of Sales	$ 64	$ 49	$ 17

California Utilities

Sempra Energy, SDG&E and SoCalGas provide certain services to each other and are charged an allocable share of the cost of such services. Also, from time-to-time, SDG&E and SoCalGas may make short-term advances of surplus cash to Sempra Energy at interest rates based on the federal funds rate plus a margin of 13 to 20 basis points, depending on the loan balance.

SoCalGas provides natural gas transportation and storage services for SDG&E and charges SDG&E for such services monthly. SoCalGas records revenues and SDG&E records a corresponding amount to cost of sales.

SDG&E and SoCalGas charge one another, as well as other Sempra Energy affiliates, for shared asset depreciation. SoCalGas and SDG&E record revenues and the affiliates record corresponding amounts to operation and maintenance expense.

The natural gas supply for SDG&E's and SoCalGas' core natural gas customers is purchased by SoCalGas as a combined procurement portfolio managed by SoCalGas. Core customers are primarily residential and small commercial and industrial customers. This core gas procurement function is considered a shared service, therefore revenues and costs related to SDG&E are not included in SoCalGas' Statements of Operations.

SDG&E has a 20-year contract for up to 155 MW of renewable power supplied from the Energía Sierra Juárez wind power generation facility. Energía Sierra Juárez is a 50-percent owned and unconsolidated joint venture of Sempra Mexico that commenced operations in June 2015.

RESTRICTED NET ASSETS

The CPUC's regulation of our capital structure limits the amount available for dividends and loans to Sempra Energy. At December 31, 2016, Sempra Energy could have received combined loans and dividends of approximately $579 million, funded by long-term debt issuance from SDG&E.

The payment and amount of future dividends are at the discretion of our board of directors. The following restrictions limit the amount of retained earnings that may be paid as common stock dividends or loaned to Sempra Energy:

- The CPUC requires that our common equity ratio be no lower than one percentage point below the CPUC-authorized percentage of our authorized capital structure. The authorized percentage at December 31, 2016 is 52 percent at SDG&E.
- The FERC requires SDG&E to maintain a common equity ratio of 30 percent or above.
- The California Utilites have a combined revolving credit line that requires each utility to maintain a ratio of consolidated indebtedness to consolidated capitalization (as defined in the agreement) of no more than 65 percent, as we discuss in Note 5.

Based on these restrictions, at December 31, 2016, SDG&E's restricted net assets were $5.1 billion, which could not be transferred to Sempra Energy.

OTHER INCOME, NET

Other Income, Net on the Statement of Operations consists of the following:

OTHER INCOME, NET
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
Allowance for equity funds used during construction	$ 46	$ 37	$ 37
Regulatory interest, net (1)	3	3	6
Sundry, net	1	(4)	(3)
Total	$ 50	$ 36	$ 40

(1) Interest on regulatory balancing accounts.

NOTE 2. NEW ACCOUNTING STANDARDS

We describe below recent pronouncements that have had or may have a significant effect on our financial condition, results of operations, cash flows or disclosures.

Accounting Standards Update (ASU) 2014-09, "Revenue from Contracts with Customers," ASU 2015-14, "Deferral of the Effective Date," ASU 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)," ASU 2016-10, "Identifying Performance Obligations and Licensing" and ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients": ASU 2014-09 provides accounting guidance for the recognition of revenue from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers. The guidance also provides a model for the measurement and recognition of gains and losses on the sale of certain nonfinancial assets, such as property and equipment, including real estate. This guidance must be adopted using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. Amending ASU 2014-09, ASU 2016-08 clarifies the implementation guidance on principal versus agent considerations, ASU 2016-10 clarifies the determination of whether a good or service is separately identifiable from other promises and revenue recognition related to licenses of intellectual property, and ASU 2016-12 provides guidance on transition, collectability, noncash consideration, and the presentation of sales and other similar taxes.

ASU 2015-14 defers the effective date of ASU 2014-09 by one year for all entities and permits early adoption on a limited basis. For public entities, ASU 2014-09 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted for fiscal years beginning after December 15, 2016, and is effective for interim periods in the year of adoption. We plan to adopt ASU 2014-09 on January 1, 2018 using the modified retrospective transition method and are currently evaluating the effect on our ongoing financial reporting. As part of our evaluation, we formed multiple working groups with oversight from a steering committee. We separated our various revenue streams into high-level categories, which will serve as the basis for accounting analysis and documentation of the impact of ASU 2014-09 on our revenue recognition. In addition, we continue to actively monitor outstanding issues currently being addressed by the American Institute of Certified Public Accountants' Revenue Recognition Working Group and the Financial Accounting Standards Board's Transition Resource Group, since conclusions reached by these groups may impact our application of these ASU's.

ASU 2015-07, "Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)": ASU 2015-07 removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured at net asset value (NAV), as well as the requirement to make specific disclosures for all investments for which the entity has elected to measure the fair value using the NAV practical expedient. We retrospectively adopted ASU 2015-07 on January 1, 2016, and it did not affect our financial condition, results of operations or cash flows. The required changes to our disclosure are reflected in Note 7.

ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities": In addition to the presentation and disclosure requirements for financial instruments, ASU 2016-01 requires entities to measure equity investments, other than those accounted for under the equity method, at fair value and recognize changes in fair value in net income. Entities will no longer be able to use the cost method of accounting for equity securities. However, for equity investments without readily determinable fair values, entities may elect a measurement alternative that will allow those investments to be recorded at cost, less impairment, and adjusted for subsequent observable price changes. Upon adoption, entities must record a cumulative-effect adjustment to the balance sheet as of the beginning of the first reporting period in which the standard is adopted. The guidance on equity securities without readily determinable fair values will be applied prospectively to all equity investments that exist as of the date of adoption of the standard.

For public entities, ASU 2016-01 is effective for fiscal years beginning after December 15, 2017. We will adopt ASU 2016-01 on January 1, 2018 as required and do not expect it to materially affect our financial condition, results of operations or cash flows. We will make the required changes to our disclosures upon adoption.

ASU 2016-02, "Leases": ASU 2016-02 requires entities to include substantially all leases on the balance sheet by requiring the recognition of right-of-use assets and lease liabilities for all leases. Entities may elect to exclude from the balance sheet those leases with a maximum possible term of less than 12 months. For lessees, a lease is classified as finance or operating, and the asset and liability are initially measured at the present value of the lease payments. For lessors, accounting for leases is largely unchanged from previous provisions of U.S. GAAP, other than certain changes to align lessor accounting to specific changes made to lessee accounting and ASU 2014-09. ASU 2016-02 also requires new qualitative and quantitative disclosures for both lessees and lessors.

For public entities, ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted, and is effective for interim periods in the year of adoption. The standard requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes optional practical expedients that may be elected, which would allow entities to continue to account for leases that commence before the effective date of the standard in accordance with previous U.S. GAAP unless the lease is modified, except for the lessee requirement to begin recognizing right-of-use assets and lease liabilities for all operating leases on the balance sheet at the reporting date. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard. As part of our evaluation, we formed a steering committee. Based on our assessment to date, we have determined that we will adopt ASU 2016-02 using the modified retrospective approach and will elect the practical expedients available under the transition guidance.

ASU 2016-05, "Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships": ASU 2016-05 provides clarification that a change in the counterparty to a derivative instrument that has been designated as a hedging instrument does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. ASU 2016-05 may be adopted prospectively or using a modified retrospective approach. We prospectively adopted ASU 2016-05 on January 1, 2016, and it did not affect our financial condition, results of operations or cash flows.

ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting": ASU 2016-09 is intended to simplify several aspects of the accounting for employee share-based payment transactions. Under ASU 2016-09, excess tax benefits and tax deficiencies are required to be recorded in earnings, and the requirement to reclassify excess tax benefits from operating to financing activities on the statement of cash flows has been eliminated. ASU 2016-09 also allows entities to withhold taxes up to the maximum individual statutory tax rate without resulting in liability classification of the award and clarifies that cash payments made to taxing authorities in connection with withheld shares should be classified as financing activities in the statement of cash flows. Additionally, the standard provides for an accounting policy election to either continue to estimate forfeitures or account for them as they occur. For public entities, ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, with early adoption permitted, and is effective for interim periods in the year of adoption.

We early adopted the provisions of ASU 2016-09 during the three months ended September 30, 2016, with an effective date of January 1, 2016. Upon adoption:

- SDG&E recognized a cumulative-effect adjustment to retained earnings and a deferred tax asset as of January 1, 2016 of $23 million, for previously unrecognized excess tax benefits from share-based compensation.
- SDG&E recognized earnings consisting of excess tax benefits on the Statement of Operations of $7 million in the year ended December 31, 2016, all of which related to the three months ended March 31, 2016.
- As now required, the excess tax benefits for SDG&E are included in Cash Flows From Operating Activities on the Statement of Cash Flows for the year ended December 31, 2016. This amendment was adopted prospectively, and therefore, we have not adjusted the Statement of Cash Flows for the prior periods presented.

Upon adoption of ASU 2016-09, we elected to continue estimating the number of awards expected to be forfeited and adjusting our estimate on an ongoing basis. All other provisions of ASU 2016-09 did not impact our financial condition, results of operations or cash flows.

ASU 2016-13, "Measurement of Credit Losses on Financial Instruments": ASU 2016-13 changes how entities will measure credit losses for most financial assets and certain other instruments. The standard introduces an "expected credit loss" impairment model that requires immediate recognition of estimated credit losses expected to occur over the remaining life of most financial assets measured at amortized cost, including trade and other receivables, loan commitments and financial guarantees. ASU 2016-13 also requires use of an allowance to record estimated credit losses on available-for-sale debt securities and expands disclosure requirements regarding an entity's assumptions, models and methods for estimating the credit losses.

For public entities, ASU 2016-13 is effective for fiscal years beginning after December 15, 2019, with early adoption permitted for fiscal years beginning after December 15, 2018. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard.

ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments": ASU 2016-15 provides guidance on how certain cash receipts and cash payments are to be presented and classified in the statement of cash flows in order to reduce diversity in practice.

For public entities, ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and is effective for interim periods in the year of adoption. An entity that elects early adoption must adopt all of the amendments in the same period. Entities must apply the guidance retrospectively to all periods presented, but may apply it prospectively if retrospective application would be impracticable. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard.

ASU 2016-18, "Restricted Cash": ASU 2016-18 requires amounts described as restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. A reconciliation between the balance sheet and the statement of cash flows must be disclosed when the balance sheet includes more than one line item for cash, cash equivalents, restricted cash and restricted cash equivalents.

For public entities, ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard.

ASU 2017-04, "Simplifying the Test for Goodwill Impairment": ASU 2017-04 removes the second step of the goodwill impairment test, which requires a hypothetical purchase price allocation. An entity will be required to apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the carrying amount of goodwill. For public entities, ASU 2017-04 is effective for annual or interim goodwill impairment tests in fiscal years beginning after December 15, 2019, with early adoption permitted. The amendments should be applied on a prospective basis. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard.

ASU 2017-05, "Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets": ASU 2017-05 clarifies the scope of accounting for the derecognition or partial sale of nonfinancial assets to exclude all businesses and nonprofit activities. ASU 2017-05 also provides a definition for in-substance nonfinancial assets and additional guidance on partial sales of nonfinancial assets. For public entities, ASU 2017-05 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. An entity may elect to apply the amendments under a retrospective or modified retrospective approach. We are currently evaluating the effect of the standard on our ongoing financial reporting and plan to adopt in conjunction with ASU 2014-09 on January 1, 2018, but have not yet selected the method of adoption.

NOTE 3. DEBT AND CREDIT FACILITIES

LINES OF CREDIT

SDG&E and SoCalGas have a combined $1 billion, five-year syndicated revolving credit agreement expiring in October 2020.

PRIMARY U.S. COMMITTED LINES OF CREDIT
(Dollars in millions)

	At December 31, 2016			
	Total facility	Commercial paper outstanding	Letters of credit outstanding	Available unused credit
California Utilities (1):				
SDG&E	$ 750	$ —	$ —	$ 750
SoCalGas	750	62	—	688
Less: subject to a combined limit of $1 billion for both utilities	(500)	—	—	(500)
	$ 1,000	$ 62	$ —	$ 938

(1) The facility also provides for the issuance of letters of credit on behalf of each utility subject to a combined letter of credit commitment of $250 million for both utilities. The amount of borrowings otherwise available under the facility is reduced by the amount of outstanding letters of credit.

Related to the commitment lines of credit in the table above:

- JPMorgan Chase Bank, N.A. serves as administrative agent for the California Utilities combined facility.
- Each facility has a syndicate of 21 lenders. No single lender has greater than a 7-percent share in any facility.
- SDG&E must maintain a ratio of indebtedness to total capitalization (as defined in each agreement) of no more than 65 percent at the end of each quarter. SDG&E is in compliance with this and all other financial covenants under its respective credit facility at December 31, 2016.
- Borrowings bear interest at benchmark rates plus a margin that varies with the borrowing utility’s credit rating.
- The California Utilities' obligations under their agreement are individual obligations, and a default by one utility would not constitute a default by the other utility or preclude borrowings by, or the issuance of letters of credit on behalf of, the other utility.

WEIGHTED AVERAGE INTEREST RATES

At December 31, 2015, the weighted average interest rate on total short-term debt at SDG&E was 1.01 percent.

LONG-TERM DEBT

The following tables show the detail and maturities of long-term debt outstanding:

LONG-TERM DEBT

(Dollars in millions)

	December 31, 2016	2015
First mortgage bonds (collateralized by plant assets):		
Bonds at variable rates (1.151% at December 31, 2016) March 9, 2017	$ 140	$ 140
1.65% July 1, 2018(1)	161	161
3% August 15, 2021	350	350
1.914% payable 2015 through February 2022	197	232
3.6% September 1, 2023	450	450
2.5% May 15, 2026	500	—
6% June 1, 2026	250	250
5% payable 2015 through December 2027(2)	—	105
5.875% January and February 2034(1)	176	176
5.35% May 15, 2035	250	250
6.125% September 15, 2037	250	250
4% May 1, 2039(1)	75	75
6% June 1, 2039	300	300
5.35% May 15, 2040	250	250
4.5% August 15, 2040	500	500
3.95% November 15, 2041	250	250
4.3% April 1, 2042	250	250
	4,349	3,989
Capital lease obligations:		
Purchased-power agreements(3)	631	670
Other	1	1
	632	671
	4,981	4,660
Current portion of long-term debt(3)	(219)	(75)
Unamortized discount on long-term debt	(11)	(10)
Unamortized debt issuance costs(3)	(32)	(31)
Total SDG&E	$ 4,719	$ 4,544

(1) Callable long-term debt not subject to make-whole provisions.

(2) Early redemption or deconsolidated in 2016.

(3) The 2015 reported amount changed to include OMEC as a capital lease and exclude debt issuance costs reported as a VIE.

MATURITIES OF LONG-TERM DEBT(1)

(Dollars in millions)

2017	$ 186
2018	207
2019	321

2020		36
2021		385
Thereafter		3,519
Total	$	4,654

(1) Excludes capital lease obligations, build-to-suit lease, market value adjustments for interest rate swaps, discounts, premiums and debt issuance costs.

There were no unsecured long-term obligations at SDG&E.

CALLABLE LONG-TERM DEBT

At the option of SDG&E, certain debt at December 31, 2016 is callable subject to premiums:

CALLABLE LONG-TERM DEBT *(Dollars in millions)*		
Not subject to make-whole provisions	$	412
Subject to make-whole provisions		3,797

FIRST MORTGAGE BONDS

We issue first mortgage bonds secured by a lien on utility plant. We may issue additional first mortgage bonds if in compliance with the provisions of our bond agreements (indentures). These indentures require, among other things, the satisfaction of pro forma earnings-coverage tests on first mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of an additional $4.5 billion of first mortgage bonds at December 31, 2016.

In May 2016, SDG&E publicly offered and sold $500 million of 2.50-percent first mortgage bonds maturing in 2026. SDG&E used the proceeds from the offering to redeem, prior to a scheduled maturity in 2027, $105 million aggregate principal amount of 5-percent, tax-exempt industrial development revenue bonds, to repay outstanding commercial paper and for other general corporate purposes.

NOTE 4. INCOME TAXES

Reconciliations of net U.S. statutory federal income tax rates to the effective income tax rates is as follows:

RECONCILIATION OF FEDERAL INCOME TAX RATES TO EFFECTIVE INCOME TAX RATES			
	Years ended December 31,		
	2016	2015	2014
U.S. federal statutory income tax rate	35%	35%	35%
State income taxes, net of federal income tax benefit	5	5	5
Depreciation	5	4	4
SONGS tax regulatory asset write-off	—	—	2
Repairs expenditures	(4)	(4)	(4)

Self-developed software expenditures	(3)	(3)	(3)
Allowance for equity funds used during construction	(2)	(2)	(2)
Resolution of prior years' income tax items	(1)	(2)	(2)
Share-based compensation	(1)	—	—
Other, net	(1)	—	—
Effective income tax rate	33%	33%	35%

In 2016, we prospectively adopted ASU 2016-09 with an effective date of January 1, 2016. ASU 2016-09 requires excess tax benefits and tax deficiencies related to employee share-based payment transactions to be recorded in earnings, instead of in shareholders' equity. We discuss the impact of adopting the provisions of this standard in Note 2.

In 2014, the effective income tax rates for SDG&E was impacted by a $17 million charge to reduce certain tax regulatory assets attributed to SDG&E's investment in SONGS that we discuss in Note 10. This charge is included in "Resolution of Prior Years' Income Tax Items" in the table above.

The CPUC requires flow-through rate-making treatment for the current income tax benefit or expense arising from certain property-related and other temporary differences between the treatment for financial reporting and income tax, which will reverse over time. Under the regulatory accounting treatment required for these flow-through temporary differences, deferred income tax assets and liabilities are not recorded to deferred income tax expense, but rather to a regulatory asset or liability, which impacts the current effective income tax rate. As a result, changes in the relative size of these items compared to pretax income, from period to period, can cause variations in the effective income tax rate. The following items are subject to flow-through treatment:

- repairs expenditures related to a certain portion of utility plant fixed assets
- the equity portion of AFUDC
- a portion of the cost of removal of utility plant assets
- Utility self-developed software expenditures
- depreciation on a certain portion of utility plant assets
- state income taxes

The final decision in the 2016 General Rate Case (2016 GRC FD) issued by the CPUC in June 2016 requires the establishment of a two-way income tax expense memorandum account to track any revenue variances resulting from certain differences arising between the income tax expense forecasted in the 2016 GRC and the income tax expense incurred from 2016 through 2018. The variances to be tracked include tax expense differences relating to:

- net revenue changes;
- mandatory tax law, tax accounting, tax procedural, or tax policy changes; and
- elective tax law, tax accounting, tax procedural, or tax policy changes.

The account will remain open, and the balance in the account will be reviewed in subsequent general rate case (GRC) proceedings, until the CPUC decides to close the account. We believe the future disposition of these tracked balances may result in refunds being directed to ratepayers to the extent tax expense incurred is lower than forecasted tax expense in the GRC process as a result of certain flow-through item deductions, as described above, or other items. We discuss the memo account further in Note 11.

Differences arising from the forecasted amounts will be tracked in the two-way income tax expense tracking account, except for the equity portion of AFUDC, which is not subject to taxation. We expect that certain amounts recorded in the tracking account may give rise to regulatory assets or liabilities until the CPUC disposes with the account. The CPUC tracking account does not affect the recovery of income tax expense in FERC formulaic rates.

The components of income tax expense are as follows:

INCOME TAX EXPENSE (BENEFIT)

(Dollars in millions)

	Years ended December 31, 2016	2015	2014
Current:			
U.S. federal	$ —	$ 12	$ (5)
U.S. state	22	77	52
Total	22	89	47
Deferred:			
U.S. federal	223	233	220
U.S. state	38	(35)	5
Total	261	198	225
Deferred investment tax credits	(3)	(3)	(2)
Total income tax expense	$ 280	$ 284	$ 270

We show the components of deferred income taxes at December 31 in the tables below:

DEFERRED INCOME TAXES

(Dollars in millions)

	December 31, 2016	2015
Deferred income tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 2,549	$ 2,392
Regulatory balancing accounts	379	234
Property taxes	42	42
Other	10	5
Total deferred income tax liabilities	2,980	2,673

Deferred income tax assets:		
Net operating losses	—	—
Tax credits	27	9
Postretirement benefits	98	90
Compensation-related items	8	11
State income taxes	—	46
Accrued expenses not yet deductible	7	36
Other	11	9
Total deferred income tax assets	151	201
Net deferred income tax liability	$ 2,829	$ 2,472

The following table summarizes our unused net operating losses (NOL) and tax credit carryforwards at December 31, 2016.

NET OPERATING LOSSES AND TAX CREDIT CARRYFORWARDS
(Dollars in millions)

	Unused amount at December 31, 2016	Year expiration begins
U.S. federal(1):		
NOLs	$ 39	2032
General business tax credits	19	2031

(1) *We have recorded deferred income tax benefits on these NOLs and tax credits, in total, because we currently believe they will be realized on a more-likely-than-not-basis.*

Following is a summary of unrecognized income tax benefits:

SUMMARY OF UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
Total	$ 22	$ 20	$ 14
Of the total, amounts related to tax positions that,	—	—	—
if recognized in future years, would	—	—	—
decrease the effective tax rate(1)	$ (19)	$ (16)	$ (11)
increase the effective tax rate(1)	13	11	6

Following is a reconciliation of the changes in unrecognized income tax benefits for the years ended December 31:

RECONCILIATION OF UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	2016	2015	2014
Balance as of January 1	$ 20	$ 14	$ 17
Increase in prior period tax positions	—	5	2
Increase in current period tax positions	2	2	—
Settlements with taxing authorities	—	(1)	(5)
Balance as of December 31	$ 22	$ 20	$ 14

It is reasonably possible that within the next 12 months, unrecognized income tax benefits could decrease due to the following:

POSSIBLE DECREASES IN UNRECOGNIZED INCOME TAX BENEFITS WITHIN 12 MONTHS
(Dollars in millions)

	At December 31,		
	2016	2015	2014
Expiration of statutes of limitations on tax assessments	$ (1)	$ (1)	$ —
Potential resolution of audit issues with various U.S. federal, state and local taxing authorities	(10)	(8)	(9)
	$ (11)	$ (9)	$ (9)

Amounts accrued for interest and penalties associated with unrecognized income tax benefits are included in income tax expense on the Statement of Operations. We summarize the amounts accrued at December 31 on the Balance Sheet for interest and penalties associated with unrecognized income tax benefits and the related expense in the table below.

INTEREST AND PENALTIES ASSOCIATED WITH UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	Interest and penalties Years ended December 31,			Accrued interest and penalties December 31,	
	2016	2015	2014	2016	2015
Interest income	$ —	$ —	$ (1)	$ —	$ —

Penalties accrued and expensed in all periods presented were zero or negligible.

INCOME TAX AUDITS

We are subject to U.S. federal income tax as well as income tax of state jurisdictions. We remain subject to examination for U.S. federal tax years after 2010 and by state tax jurisdictions for tax years after 2008.

NOTE 5. EMPLOYEE BENEFIT PLANS

We are required by applicable U.S. GAAP to:

- recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status in the statement of financial position;
- measure a plan's assets and its obligations that determine its funded status as of the end of the fiscal year (with limited exceptions); and
- recognize changes in the funded status of pension and other postretirement benefit plans in the year in which the changes occur. Generally, those changes are reported in other comprehensive income and as a separate component of shareholders' equity.

The detailed information presented below covers the employee benefit plans of Sempra Energy and its principal subsidiaries.

Sempra Energy has funded and unfunded noncontributory traditional defined benefit and cash balance plans, including separate plans for SDG&E, which collectively cover all eligible employees, including members of the Sempra Energy board of directors who were participants in a predecessor plan on or before June 1, 1998. Pension benefits under the traditional defined benefit plans are based on service and final average earnings, while the cash balance plans provide benefits using a career average earnings methodology.

Sempra Energy also has other postretirement benefit plans (PBOP), including separate plans for SDG&E and SoCalGas, which collectively cover all employees. The life insurance plans are both contributory and noncontributory, and the health care plans are contributory. Participants' contributions are adjusted annually. Other postretirement benefits include medical benefits for retirees' spouses.

Pension and other postretirement benefits costs and obligations are dependent on assumptions used in calculating such amounts. We review these assumptions on an annual basis and update them as appropriate. We consider current market conditions, including interest rates, in making these assumptions. We use a December 31 measurement date for all of our plans.

RABBI TRUST

In support of its Supplemental Executive Retirement, Cash Balance Restoration and Deferred Compensation Plans, Sempra Energy maintains dedicated assets, including a Rabbi Trust and investments in life insurance contracts, which totaled $430 million and $464 million at December 31, 2016 and 2015, respectively.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Special Termination Benefits Affecting 2016

In 2016, certain nonrepresented employees age 62 or older with 5 years of service or age 55 to 61 with 10 years of service that retired under the Voluntary Retirement Enhancement Program offered in that year received an additional postretirement health benefit in the form of a $100,000 Health Reimbursement Account. We treated the benefit obligation attributable to the Health Reimbursement Account as a special termination benefit. This resulted in increases to the recorded liability for other postretirement benefits of $14 million for SDG&E.

The Voluntary Retirement Enhancement Program resulted in a higher than expected number of retirements in December 2016. As a result, the total lump sum benefits paid from the SDG&E qualified pension plan in 2016 exceeded the settlement threshold, which triggered settlement accounting and a resulting reduction of the recorded pension liability and pension plan assets of $75 million and a settlement charge of $16 million. This settlement charge was recorded as a regulatory asset on the Balance Sheet. A measurement date of December 31, 2016 was used for the settlement accounting, as the year-to-date lump sum benefit payments first exceeded the settlement threshold in December 2016.

Benefit plan Amendments Affecting 2015

Effective January 1, 2016, the point of service medical benefit provided to retirees under the age of 65 at our domestic companies, except the represented retirees, is no longer provided by the PBOP plans. This change resulted in a decrease in other postretirement benefit obligations by a negligible amount.

Benefit Obligations and Assets

The following the table provides a reconciliation of the changes in the plan's projected benefit obligations and the fair value of assets during 2016 and 2015, and a statement of the funded status at December 31, 2016 and 2015:

PROJECTED BENEFIT OBLIGATION, FAIR VALUE OF ASSETS AND FUNDED STATUS
SAN DIEGO GAS & ELECTRIC COMPANY
(Dollars in millions)

	Pension benefits		Other postretirement benefits	
	2016	2015	2016	2015
CHANGE IN PROJECTED BENEFIT OBLIGATION				
Net obligation at January 1	$ 965	$ 1,011	$ 165	$ 200
Service cost	29	29	5	7
Interest cost	41	39	7	8
Contributions from plan participants	—	—	7	7
Actuarial loss (gain)	7	(52)	6	(43)
Benefit payments	(25)	(56)	(14)	(14)
Special termination benefits	—	—	14	—
Settlements	(75)	—	—	—
Transfer of liability to other plans	(7)	(6)	—	—
Net obligation at December 31	935	965	190	165

CHANGE IN PLAN ASSETS				
Fair value of plan assets at January 1	752	828	161	164
Actual return on plan assets	59	(24)	13	(3)
Employer contributions	3	2	2	7
Contributions from plan participants	—	—	7	7
Benefit payments	(25)	(56)	(14)	(14)
Settlements	(75)	—	—	—
Transfer of assets from other plans	—	2	—	—
Fair value of plan assets at December 31	714	752	169	161
Funded status at December 31	$ (221)	$ (213)	$ (21)	$ (4)
Net recorded liability at December 31	$ (221)	$ (213)	$ (21)	$ (4)

Actuarial losses (gains) fluctuate based on changes in assumptions that we describe below in "Assumptions for Pension and Other Postretirement Benefit Plans" and updates to census data. In 2015 and 2016, the Society of Actuaries released updated mortality improvement projection scales, reflecting observed longevity improvements in its mortality tables. We have incorporated these assumptions, adjusted for the SDGE's actual mortality experience, in our calculations for each of those years.

Net Assets and Liabilities

The assets and liabilities of the pension and other postretirement benefit plans are affected by changing market conditions as well as when actual plan experience is different than assumed. Such events result in investment gains and losses, which we defer and recognize in pension and other postretirement benefit costs over a period of years. We recognize realized and unrealized investment gains and losses during the current year.

We use the 10-percent corridor accounting method. Under the corridor accounting method, if as of the beginning of a year unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, the excess is amortized over the average remaining service period of active participants. The 10-percent corridor accounting method helps mitigate volatility of net periodic costs from year to year.

We recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as assets or liabilities, respectively; unrecognized changes in these assets and/or liabilities are normally recorded in Accumulated Other Comprehensive Income (Loss) on the balance sheet. We record regulatory assets and liabilities that offset the funded pension and other postretirement plans' assets or liabilities, as these costs are expected to be recovered in future utility rates based on agreements with regulatory agencies.

We record annual pension and other postretirement net periodic benefit costs equal to the contributions to our plans as authorized by the CPUC. The annual contributions to the pension plans are limited to a minimum required funding amount as determined by the IRS. The annual contributions to the other postretirement plans are equal to the lesser of the maximum tax deductible amount or the net periodic cost calculated in accordance with U.S. GAAP for pension and other postretirement benefit plans. Any differences between booked net periodic benefit cost and amounts contributed to the pension and other postretirement plans are disclosed as regulatory adjustments in accordance with U.S. GAAP for rate-regulated entities.

The net liability is included in the following categories on the Balance Sheet at December 31:

PENSION AND OTHER POSTRETIREMENT BENEFIT OBLIGATIONS, NET OF PLAN ASSETS AT DECEMBER 31
(Dollars in millions)

	Pension benefits		Other postretirement benefits	
	2016	2015	2016	2015
Current liabilities	$ (10)	$ (5)	$ —	$ —
Noncurrent liabilities	(211)	(208)	(21)	(4)
Net recorded liability	$ (221)	$ (213)	$ (21)	$ (4)

Amounts recorded in Accumulated Other Comprehensive Income (Loss) at December 31, 2016 and 2015, net of income tax effects and amounts recorded as regulatory assets, are as follows:

AMOUNTS IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

	Pension benefits	
	2016	2015
Net actuarial loss	$ (8)	$ (8)
Prior service cost	—	—
Total	$ (8)	$ (8)

The accumulated benefit obligation for defined benefit pension plan at December 31, 2016 and 2015 was as follows:

ACCUMULATED BENEFIT OBLIGATION
(Dollars in millions)

	2016	2015
Accumulated benefit obligation	$ 904	$ 939

SDG&E has an unfunded and funded pension plan. The following table shows the obligations of funded pension plans with benefit obligations in excess of plan assets at December 31:

OBLIGATIONS OF FUNDED PENSION PLANS
(Dollars in millions)

	2016	2015
Projected benefit obligation	$ 902	$ 927
Accumulated benefit obligation	874	906
Fair value of plan assets	714	752

Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost and pretax amounts recognized in Other Comprehensive Income (Loss) for the years ended December 31:

NET PERIODIC BENEFIT COST AND AMOUNTS RECOGNIZED IN OTHER COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

	Pension benefits			Other postretirement benefits		
	2016	2015	2014	2016	2015	2014
NET PERIODIC BENEFIT COST						
Service cost	$ 29	$ 29	$ 30	$ 5	$ 7	$ 7
Interest cost	41	39	43	7	8	9
Expected return on assets	(49)	(54)	(55)	(12)	(11)	(10)
Amortization of:						
Prior service cost	1	8	2	3	3	2
Actuarial loss (gain)	10	2	4	(1)	—	—
Settlement charge	16	—	19	—	—	—
Special termination benefits	—	—	—	14	—	5
Regulatory adjustment	(45)	(20)	12	(14)	—	1
Total net periodic benefit cost	3	4	55	2	7	14
CHANGES IN PLAN ASSETS AND BENEFIT OBLIGATIONS RECOGNIZED IN OTHER COMPREHENSIVE INCOME (LOSS)						
Net loss (gain)	1	(6)	8	—	—	—
Amortization of actuarial loss	(1)	(1)	(3)	—	—	—
Total recognized in other comprehensive (loss) income	—	(7)	5	—	—	—
Total recognized in net periodic benefit cost and other comprehensive (loss) income	$ 3	$ (3)	$ 60	$ 2	$ 7	$ 14

The estimated net loss for the pension and other postretirement benefit plans that will be amortized from Accumulated Other Comprehensive Income (Loss) into net periodic benefit cost in 2017 is $1 million. Negligible amount of estimated prior service cost will be similarly amortized in 2017.

Assumptions for Pension and Other Postretirement Benefit Plans

Benefit Obligation and Net Periodic Benefit Cost

We develop the discount rate assumptions based on the results of a third party modeling tool that matches each plan's expected cash flows to interest rates and expected maturity values of individually selected bonds in a hypothetical portfolio. The model controls the level of accumulated surplus that may result from the selection of bonds based solely on their premium yields by limiting the number of years to look back for selection to 3 years for pre-30-year and 6 years for post-30-year benefit payments. Additionally, the model ensures that an adequate number of bonds are selected in the portfolio by limiting the amount of the plan's benefit payments that can be met by a single bond to 7.5 percent.

We selected individual bonds from a universe of Bloomberg AA-rated bonds which:

- have an outstanding issue of at least $50 million;
- are non-callable (or callable with make-whole provisions);

- exclude collateralized bonds; and
- exclude the top and bottom 10 percent of yields to avoid relying on bonds which might be mispriced or misgraded.

This selection methodology also mitigates the impact of market volatility on the portfolio by excluding bonds with the following characteristics:

- The isssuer is on review for downgrade by a major rating agency if the downgrade would eliminate from the portfolio
- Recent events have caused significant price volatility to which rating agencies have not reacted.
- Lack of liquidity is causing price quotes to vary significantly from broker to broker.

We believe that this bond selection approach provides the best estimate of discount rates to estimate settlement values for our plans' benefit obligations as required by applicable U.S. GAAP.

Long-tern return on assets is based on the weighted-average of the plans' investment allocation as of the measurement date and the expected returns for those asset types.

We amortize prior service cost using straight line amortization over average future service (or average expected lifetime for plans where participants are substantially inactive employees), which is an alternative method allowed under U.S. GAAP.

The significant assumptions affecting benefit obligation and net periodic benefit cost are as follows:

WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION
AT DECEMBER 31

	Pension benefits		Other postretirement benefits	
	2016	2015	2016	2015
Discount rate	4.08%	4.35%	4.15%	4.50%
Rate of compensation increase	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00

WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COST
YEARS ENDED DECEMBER 31

	Pension benefits			Other postretirement benefits		
	2016	2015	2014	2016	2015	2014
Discount rate	4.35%	4.00%	4.69%	4.50%	4.15%	5.00%
Expected return on plan assets	7.00	7.00	7.00	6.90	6.91	6.88
Rate of compensation increase	2.00-10.00	2.00-10.00	3.50-10.00	2.00-10.00	2.00-10.00	3.50-10.00

Health Care Cost Trend Rates

Assumed health care cost trend rates have a significant effect on the amounts that we report for the health care plan costs. Following are the health care cost trend rates applicable to our postretirement benefit plans:

ASSUMED HEALTH CARE COST TREND RATES
AT DECEMBER 31

	Other postretirement benefit plans					
	Pre-65 retirees			Retirees aged 65 years and older		
	2016	2015	2014	2016	2015	2014

Health care cost trend rate assumed for next year	8.00 %	8.10 %	7.75 %	5.50 %	5.50 %	5.25 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	5.00 %	5.00 %	5.00 %	4.50 %	4.50 %	4.50 %
Year the rate reaches the ultimate trend	2022	2022	2020	2022	2022	2020

A one-percent change in assumed health care cost trend rates would have had the following effects in 2016:

EFFECT OF ONE-PERCENT CHANGE IN ASSUMED HEALTH CARE COST TREND RATES
(Dollars in millions)

	1% increase	1% decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 1	$ (1)
Effect on the health care component of the accumulated other postretirement benefit obligations	6	(5)

Plan Assets

Investment Allocation Strategy for Sempra Energy's Pension Master Trust

Sempra Energy's pension master trust holds the investments for our pension plans and a portion of the investments for our other postretirement benefit plans. We maintain additional trusts as we discuss below for certain of the California Utilities' other postretirement benefit plans. Other than through indexing strategies, the trusts do not invest in securities of Sempra Energy.

The current asset allocation objective for the pension master trust is to protect the funded status of the plans while generating sufficient returns to cover future benefit payments and accruals. We assess the portfolio performance by comparing actual returns with relevant benchmarks. Currently, the pension plans' target asset allocations are

- 38 percent domestic equity
- 26 percent international equity
- 18 percent long credit
- 8 percent ultra-long duration government securities
- 5 percent global high yield credit
- 5 percent real assets

The asset allocation of the plans is reviewed by our Plan Funding Committee and our Pension and Benefits Investment Committee (the Committees) on a regular basis. When evaluating strategic asset allocations, the Committees consider many variables, including:

- long-term cost
- variability and level of contributions
- funded status
- a range of expected outcomes over varying confidence levels

We maintain allocations at strategic levels with reasonable bands of variance.

In accordance with the Sempra Energy pension investment guidelines, derivative financial instruments may be used by the pension master trust's equity and fixed income portfolio investment managers to equitize cash, hedge certain exposures, and as substitutes for certain types of fixed income securities.

Rate of Return Assumption

The expected return on assets in our pension and other postretirement benefit plans is based on the weighted-average of the plans' investment allocations to specific asset classes as of the measurement date. We arrive at a 7-percent expected return on assets by considering both the historical and forecasted long-term rates of return on those asset classes. We expect a return of between 7 percent and 9 percent on return-seeking assets and between 3 percent and 5 percent for risk-mitigating assets. Certain trusts that hold assets for the SDG&E other postretirement benefit plan are subject to taxation, which impacts the expected after-tax return on assets in the plan.

Concentration of Risk

Plan assets are diversified across global equity and bond markets, and concentration of risk in any one economic, industry, maturity or geographic sector is limited.

Investment Strategy for SDG&E's Other Postretirement Benefit Plans

SDG&E's other postretirement benefit plans are funded by cash contributions from SDG&E and their current retirees. The assets of these plans are placed into the pension master trust and other Voluntary Employee Beneficiary Association trusts. The assets in the Voluntary Employee Beneficiary Association trusts are invested at an allocation similar to the pension master trust, with 75 percent invested in return-seeking and 25 percent invested in risk-mitigating assets. This allocation is periodically reviewed to ensure that plan assets are best positioned to meet plan obligations.

Fair Value of Pension and Other Postretirement Benefit Plan Assets

We classify the trusts for the SDG&E's other postretirement benefit plans based on the fair value hierarchy, except for certain investments measured at net asset value (NAV).

The following are descriptions of the valuation methods and assumptions we use to estimate the fair values of investments held by pension and other postretirement benefit plan trusts.

Equity Securities – Equity securities are valued using quoted prices listed on nationally recognized securities exchanges.

Fixed Income Securities – Certain fixed income securities are valued at the closing price reported in the active market in which the security is traded. Other fixed income securities are valued based on yields currently available on comparable securities of issuers with similar credit ratings. When quoted prices are not available for identical or similar securities, the security is valued under a discounted cash flows approach that maximizes observable inputs, such as current yields of similar instruments, but includes adjustments for certain risks that may not be observable, such as credit and liquidity risks. Certain high yield fixed-income securities are valued by applying a price adjustment to the bid side to calculate a mean and ask value. Adjustments can vary based on maturity, credit standing, and reported trade frequencies. The bid to ask spread is determined by the investment manager based on the review of the available market information.

Registered Investment Companies – Investments in mutual funds sponsored by a registered investment company are valued based on exchange listed prices for equity and certain fixed income securities or are valued under a discounted cash flows a pproach that maximizes observable inputs, such as current yields of similar instruments, but includes adjustments for certain risks that may not be observable, such as credit and liquidity risks for the remaining fixed income securities. Where the value is a quoted price in an active market, the investment is classified within Level 1 of the fair value hierarchy.

Common/Collective Trusts – Investments in common/collective trust funds are valued based on the NAV of units owned, which is based on the current fair value of the funds' underlying assets.

Venture Capital Funds – These funds consist of investments in private equities that are held by limited partnerships following various strategies, including venture capital and corporate finance. The partnerships generally have limited lives of 10 years, after which liquidating distributions will be received. The value is determined based on the NAV of the proportionate share of an ownership interest in partners' capital.

Real Estate Funds – Investments in real estate funds are valued at NAV per share, based on the fair value of the underlying investments.

Derivative Financial Instruments – Forward currency contracts are valued at the prevailing forward exchange rate of the underlying currencies, and unrealized gain (loss) is recorded daily. Fixed income futures and options are marked to market daily. Equity index future contracts are valued at the last sales price quoted on the exchange on which they primarily trade.

The methods described are intended to produce a fair value calculation that is indicative of net realizable value or reflective of fair values. However, while management believes the valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

We provide more discussion of fair value measurements in Notes 1 and 8. The following tables set forth by level within the fair value hierarchy a summary of the investments in our pension and other postretirement benefit plan trusts measured at fair value on a recurring basis.

The were no transfers into or out of Level 1, Level 2 or Level 3 during the periods presented, except for investments measured at NAV as required by ASU 2015-07, which we adopted retrospectively as of January 1, 2016 and discuss in Note 2. There were no changes in the valuation techniques used in recurring fair value measurement.

SDG&E holds a proportionate share of investment assets in the pension master trust at Sempra Energy Consolidated. The fair values of our pension plan assets by asset category are as follows:

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF PENSION PLANS

(Dollars in millions)

	Fair value at December 31, 2016		
	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Equity securities:			
Domestic	$ 884	$ —	$ 884
International	522	—	522
Registered investment companies	127	—	127
Fixed income securities:			
Domestic government bonds	214	32	246
International government bonds	—	9	9
Domestic corporate bonds	—	346	346
International corporate bonds	—	94	94
Registered investment companies	—	14	14
Total investment assets in the fair value hierarchy	$ 1,747	$ 495	$ 2,242

Investments measured at NAV (1):		
Common/collective trusts		223
Venture capital funds and real estate funds		4
Total investment assets(2)	$	2,469
SDG&E's proportionate share of investment assets	$	717
SoCalGas' proportionate share of investment assets	$	1,585

(1) Reflects the retrospective adoption of ASU 2015-07 as of January 1, 2016, as we discuss in Note 2. Prior to adoption, we included investments measured at NAV within the fair value hierarchy.

(2) Excludes cash and cash equivalents of $14 million and accounts payable of $24 million.

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF PENSION PLANS

(Dollars in millions)

	Fair value at December 31, 2015		
	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Equity securities:			
Domestic	$ 893	$ 7	$ 900
International	543	1	544
Registered investment companies	124	—	124
Fixed income securities:			
Domestic government bonds	124	31	155
International government bonds	—	10	10
Domestic corporate bonds	—	338	338
International corporate bonds	—	100	100
Registered investment companies	—	7	7

Other	1	—	1
Total investment assets in the fair value hierarchy	$ 1,685	$ 494	$ 2,179
Investments measured at NAV (1):			
Common/collective trusts			312
Venture capital funds and real estate funds			4
Total investment assets(2)			$ 2,495
SDG&E's proportionate share of investment assets(3)			$ 753
SoCalGas' proportionate share of investment assets			$ 1,544

(1) Reflects the retrospective adoption of ASU 2015-07 as of January 1, 2016, as we discuss in Note 2. Prior to adoption, we included investments measured at NAV within the fair value hierarchy.

(2) Excludes cash and cash equivalents of $14 million and accounts payable of $25 million.

(3) Excludes transfers receivable from other plans of $2 million at SDG&E.

The fair values by asset category of SDG&E's other postretirement benefit plan (PBOP plan trusts) are as follows:

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF OTHER POSTRETIREMENT BENEFIT PLANS
(Dollars in millions)

	Fair value at December 31, 2016		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 41	—	$ 41
International	24	—	24
Registered investment companies	46	—	46
Fixed income securities:			
Domestic government bonds	10	1	11
Domestic corporate bonds	—	16	16
International corporate bonds	—	3	3

Registered investment companies	—	17	17
Total investment assets in the fair value hierarchy	121	37	158
Investments measured at NAV - Common/collective trusts (1)			11
Total investment assets(2)			169

(1) Reflects the retrospective adoption of ASU 2015-07 as of January 1, 2016, as we discuss in Note 2. Prior to adoption, we included investments measured at NAV within the fair value hierarchy.

(2) Excludes cash and cash equivalents of $1 million and accounts payable of $1 million held in SDG&E PBOP plan trusts.

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF OTHER POSTRETIREMENT BENEFIT PLANS
(Dollars in millions)

	Fair value at December 31, 2015		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 39	$ —	$ 39
International	24	—	24
Registered investment companies	41	—	41
Fixed income securities:			
Domestic government bonds	5	3	8
Domestic corporate bonds	—	15	15
International corporate bonds	—	4	4
Registered investment companies	—	16	16

Total investment assets in the fair value hierarchy	109	38	147
Investments measured at NAV - Common/collective trusts (1)			14
Total investment assets(2)			161

(1) Reflects the retrospective adoption of ASU 2015-07 as of January 1, 2016, as we discuss in Note 2. Prior to adoption, we included investments measured at NAV within the fair value hierarchy.

(2) Excludes cash and cash equivalents of $1 million and accounts payable of $1 million held in SDG&E PBOP plan trusts.

Future Payments

We expect to contribute the following amounts to our pension and other postretirement benefit plans in 2017:

EXPECTED CONTRIBUTIONS *(Dollars in millions)*		
Pension plans	$	38
Other postretirement benefit plans		5

The following table shows the total benefits we expect to pay for the next 10 years to current employees and retirees from the plans or from company assets.

EXPECTED BENEFIT PAYMENTS *(Dollars in millions)*	SDG&E	
	Pension benefits	Other postretirement benefits
2017	$ 94	$ 10
2018	84	11
2019	81	11
2020	77	12
2021	73	12
2022-2026	322	61

SAVINGS PLANS

We offered trusteed savings plans to all employees. Participation in the plans is immediate for salary deferrals for all employees who are eligible upon completion of one year of service. Subject to plan provisions, employees may contribute from one percent to 50 percent of their eligible earnings, subject to annual IRS limits.

Through March 27, 2015, we made matching contributions for all employees after one year of the employee's completed service. Beginning March 28, 2015, we make matching contributions for employees immediately as of the date of hire who continue to receive matching contributions after one year of the employee's completed service.

Also beginning March 28, 2015, employer contribution amounts for all employees are equal to 50 percent of the first 6 percent, plus 20 percent of the next 5 percent, of eligible earnings contributed by employees. Prior to that, employer contribution amounts for these employees were 50 percent of the first 6 percent of eligible earnings contributed by the employees and, if certain company goals were met, an additional amount related to incentive compensation payments.

Contributions to the savings plans were as follows:

CONTRIBUTIONS TO SAVINGS PLANS
(Dollars in millions)

	2016	2015	2014
SDG&E	$ 15	$ 17	$ 15

The market value of Sempra Energy common stock held by the savings plans was $1.1 billion at both December 31, 2016 and 2015.

NOTE 6. SHARE-BASED COMPENSATION

SEMPRA ENERGY EQUITY COMPENSATION PLANS

Sempra Energy has share-based compensation plans intended to align employee and shareholder objectives related to the long-term growth of Sempra Energy. The plans permit a wide variety of share-based awards, including:

- non-qualified stock options
- incentive stock options
- restricted stock awards (RSAs)
- restricted stock units (RSUs)
- stock appreciation rights
- performance awards
- stock payments
- dividend equivalents

Eligible SDG&E employees participate in Sempra Energy's share-based compensation plans as a component of their compensation package.

In the three years ended December 31, 2016, Sempra Energy had the following types of equity awards outstanding:

- Non-Qualified Stock Options: Options have an exercise price equal to the market price of the common stock at the date of grant, are service-based, become exercisable over a four-year period, and expire 10 years from the date of grant. Vesting and/or the ability to exercise may be accelerated upon a change in control, in accordance with severance pay agreements, in accordance with the terms of the grant, or upon eligibility for retirement. Options are subject to forfeiture or earlier expiration when an employee terminates employment.

- Performance-Based Restricted Stock Units: These RSU awards generally vest in Sempra Energy common stock at the end of three-year (for awards granted during or after 2015) or four-year performance periods based on Sempra Energy's total return to shareholders relative to that of specified market indices or based on the compound annual growth rate of Sempra Energy's EPS. The comparative market indices for the awards that vest based on total return to shareholders are the Standard & Poor's (S&P) 500 Utilities Index and the S&P 500 Index. We primarily use long-term analyst consensus growth estimates for S&P 500 Utilities Index peer companies to develop our targets for awards that vest based on EPS growth.
    - For awards granted in 2013 or earlier, if Sempra Energy's total return to shareholders exceeds target levels, up to an additional 50 percent of the number of granted RSUs may be issued.
    - For awards granted during or after 2014, up to an additional 100 percent of the granted RSUs may be issued if total return to shareholders or EPS growth exceeds target levels.
    - For awards granted during or after 2015 that vest based on Sempra Energy's total return to shareholders, a modifier adds 20 percent to the award's payout (as initially calculated based on total return to shareholders relative to that of specified market indices) for total shareholder return performance in the top quartile relative to historical benchmark data for Sempra Energy and reduces the award's payout by 20 percent for performance in the bottom quartile. However, in no event will more than an additional 100 percent of the granted RSUs be issued. If performance falls within the second or third quartiles, the modifier is not triggered, and the payout is based solely on total return to shareholders relative to that of specified market indices.

If Sempra Energy's total return to shareholders or EPS growth is below the target levels but above threshold performance levels, shares are subject to partial vesting on a pro rata basis.

- *Other Performance-Based Restricted Stock Units:* RSUs were granted in 2014 and 2015 in connection with the creation of Cameron LNG JV.
    - The 2014 awards vest to the extent that the Compensation Committee of Sempra Energy's Board of Directors determines that the objectives of the joint venture are continuing to be achieved. These awards vest on the anniversary of the grant date over a period of either two or three years.
    - The 2015 awards vest to the extent that the Compensation Committee of Sempra Energy's Board of Directors determines that Sempra Energy has achieved positive cumulative net income for fiscal years 2015 through 2017 and Cameron LNG JV has commenced commercial operations of the first train.

- *Service-Based Restricted Stock Units:* RSUs may also be service-based; these generally vest at the end of three-year (for awards granted during or after 2015) or four-year service periods.
- *Restricted Stock Awards:* RSAs are solely service-based and are generally exercisable at the end of four years of service. Accelerated vesting of RSAs may occur upon eligibility for retirement. Holders of RSAs have full voting rights.

For RSA and RSU awards, vesting may be subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control under the applicable long-term incentive plan, in accordance with severance pay agreements, or at the discretion of the Compensation Committee of Sempra Energy's Board of Directors. Dividend equivalents on shares subject to RSAs and RSUs are reinvested to purchase additional shares that become subject to the same vesting conditions as the RSAs and RSUs to which the dividends relate.

SHARE-BASED AWARDS AND COMPENSATION EXPENSE

At December 31, 2016, 5,627,118 shares were authorized and available for future grants of share-based awards. Our practice is to satisfy share-based awards by issuing new shares rather than by open-market purchases.

We measure and recognize compensation expense for all share-based payment awards made to our employees and directors based on estimated fair values on the date of grant. We recognize compensation costs net of an estimated forfeiture rate (based on historical experience) and recognize the compensation costs for non-qualified stock options and RSAs and RSUs on a straight-line basis over the requisite service period of the award, which is generally three or four years. However, in the year that an employee becomes eligible for retirement, the remaining expense related to the employee's awards is recognized immediately. Substantially all awards outstanding are classified as equity instruments; therefore, we recognize additional paid in capital as we recognize the compensation expense associated with the awards.

As we discuss in Note 2, we prospectively adopted ASU 2016-09 effective January 1, 2016, which requires that we recognize in earnings the tax benefits (or deficiencies) resulting from tax deductions that are in excess of (or less than) tax benefits related to compensation cost recognized for share-based payments. Prior to adoption, we recorded excess tax benefits from share-based compensation within SDG&E's Shareholders' Equity.

SDG&E records an expense for the plans to the extent that employees participate in the plans and/or SDG&E is allocated a portion of the Sempra Energy plans' corporate staff costs. Expenses and capitalized compensation costs recorded were as follows:

SHARE-BASED COMPENSATION EXPENSE
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
SDG&E:			
Share-based compensation expense, before income taxes	$ 7	$ 8	$ 8
Income tax benefit	(3)	(3)	(3)
	$ 4	$ 5	$ 5
Capitalized share-based compensation cost	$ 4	$ 4	$ 3

SEMPRA ENERGY NON-QUALIFIED STOCK OPTIONS

We use a Black-Scholes option-pricing model to estimate the fair value of each non-qualified stock option grant. The use of a valuation model requires us to make certain assumptions about selected model inputs. Expected volatility is calculated based on the historical volatility of Sempra Energy's stock price. We base the average expected life for options on the contractual term of the option and expected employee exercise and post-termination behavior. The risk-free interest rate is based on U.S. Treasury zero-coupon issues with a remaining term equal to the expected life assumed at the date of the grant.

NOTE 7. DERIVATIVE FINANCIAL STATEMENTS

We use derivative instruments primarily to manage exposures arising in the normal course of business. Our principal exposures are commodity market risk, benchmark interest rate risk and foreign exchange rate exposures. Our use of derivatives for these risks is integrated into the economic management of our anticipated revenues, anticipated expenses, assets and liabilities. Derivatives may be effective in mitigating these risks (1) that could lead to declines in anticipated revenues or increases in anticipated expenses, or (2) that our asset values may fall or our liabilities increase. Accordingly, our derivative activity summarized below generally represents an impact that is intended to offset associated revenues, expenses, assets or liabilities that are not included in the table below.

In certain cases, we apply the normal purchase or sale exception to derivative instruments and have other commodity contracts that are not derivatives. These contracts are not recorded at fair value and are therefore excluded from the disclosures below.

In all other cases, we record derivatives at fair value on the Balance Sheet. We designate each derivative as (1) a cash flow hedge, (2) a fair value hedge, or (3) undesignated. Depending on the applicability of hedge accounting and the requirement to pass impacts through to customers, the impact of derivative instruments may be offset in other comprehensive income (loss) (cash flow hedge), on the balance sheet (fair value hedges and regulatory offsets), or recognized in earnings. We classify cash flows from the settlements of derivative instruments as operating activities on the Statement of Cash Flows.

HEDGING ACCOUNTING

We may designate a derivative as a cash flow hedging instrument if it effectively converts anticipated cash flows associated with revenues or expenses to a fixed dollar amount. We may utilize cash flow hedge accounting for derivative commodity instruments, foreign currency instruments and interest rate instruments. Designating cash flow hedges is dependent on the business context in which the instrument is being used, the effectiveness of the instrument in offsetting the risk that the future cash flows of a given revenue or expense item may vary, and other criteria.

We may designate an interest rate derivative as a fair value hedging instrument if it effectively converts our own debt from a fixed interest rate to a variable rate. The combination of the derivative and debt instrument results in fixing that portion of the fair value of the debt that is related to benchmark interest rates. Designating fair value hedges is dependent on the instrument being used, the effectiveness of the instrument in offsetting changes in the fair value of our debt instruments, and other criteria.

ENERGY DERIVATIVES

Our market risk is primarily related to natural gas and electricity price volatility and the specific physical locations where we transact. We use energy derivatives to manage these risks. The use of energy derivatives in our various businesses depends on the particular energy market, and the operating and regulatory environments applicable to the business, as follows:From time to time, we may use other energy derivatives to hedge exposures such as the price of vehicle fuel.

- We use natural gas and electricity derivatives, for the benefit of customers, with the objective of managing price risk and basis risks, and stabilizing and lowering natural gas and electricity costs. These derivatives include fixed price natural gas and electricity positions, options, and basis risk instruments, which are either exchange-traded or over-the-counter financial instruments, or bilateral physical transactions. This activity is governed by risk management and transacting activity plans that have been filed with and approved by the CPUC. Natural gas and electricity derivative activities are recorded as commodity costs that are offset by regulatory account balances and are recovered in rates. Net commodity cost impacts on the Statement of Operations are reflected in Cost of Electric Fuel and Purchased Power or in Cost of Natural Gas.uel and Purchased Power on the Statement of Operations.
- We are allocated and may purchase congestion revenue rights (CRRs), which serve to reduce the regional electricity price volatility risk that may result from local transmission capacity constraints. Unrealized gains and losses do not impact earnings, as they are offset by regulatory account balances. Realized gains and losses associated with CRRs, which are recoverable in rates, are recorded in Cost of Electric Fuel and Purchased Power on the Statement of Operations.
- From time to time, we may use other energy derivatives to hedge exposures such as the price of vehicle fuel.

We summarized net energy derivative volumes at December 31, 2016 and 2015 as follows:

NET ENERGY DERIVATIVE VOLUMES *(Quantities in millions)*			
		December 31,	
Commodity	Unit of measure	2016	2015
Natural gas	MMBtu(1)	48	70
Electricity	MWH(2)	4	1
Congestive Revenue Rights	MWh	18	36

(1) Million British thermal units
(2) Megawatt hours

In addition to the amounts noted above, we frequently use commodity derivatives to manage risks associated with the physical locations of contractual obligations and assets, such as natural gas purchases and sales.

FINANCIAL STATEMENT PRESENTATION

The following tables provide the fair values of derivative instruments on the Balance Sheet at December 31, 2016 and 2015, including the amount of cash collateral receivables that were not offset, as the cash collateral is in excess of liability positions.

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET
(Dollars in millions)

	December 31, 2016			
	Current assets: Fixed-price contracts and other derivatives(1)	Other assets: Sundry	Current liabilities: Fixed-price contracts and other derivatives(2)	Deferred credits and other liabilities: Fixed-price contracts and other derivatives
Derivatives not designated as hedging instruments:				
Commodity contracts subject to rate recovery	$ 33	$ 73	$ (51)	$ (150)
Associated offsetting commodity contracts	(6)	(1)	6	1
Associated offsetting cash collateral	—	—	3	13
Net amounts presented on the balance sheet	27	72	(42)	(136)
Additional cash collateral for commodity contracts not subject				

to rate recovery	1	—	—	—
Additional cash collateral for commodity contracts subject to rate recovery	30	—	—	—
Total(3)	$ 58	$ 72	$ (42)	$ (136)

(1) Included in Current Assets.

(2) Included in Current Liabilities.

(3) Normal purchase contracts previously measured at fair value are excluded.

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET

(Dollars in millions)

	December 31, 2015			
	Current assets: Fixed-price contracts and other derivatives(1)	Other assets: Sundry	Current liabilities: Fixed-price contracts and other derivatives(2)	Deferred credits and other liabilities: Fixed-price contracts and other derivatives
Derivatives not designated as hedging instruments:				
Commodity contracts not subject to rate recovery	$ —	$ —	$ (1)	$ —
Associated offsetting cash collateral	—	—	1	—
Commodity contracts subject to rate recovery	27	49	(60)	(64)

Associated offsetting commodity contracts	(2)	(2)	2	2
Associated offsetting cash collateral	—	—	28	26
Net amounts presented on the balance sheet	25	47	(30)	(36)
Additional cash collateral for commodity contracts not subject to rate recovery	1	—	—	—
Additional cash collateral for commodity contracts subject to rate recovery	27	—	—	—
Total(3)	$ 53	$ 47	$ (30)	$ (36)

(1) Included in Current Assets.

(2) Included in Current Liabilities.

(3) Normal purchase contracts previously measured at fair value are excluded.

The effects of derivative instruments not designated as hedging instruments on the Statement of Operations for the years ended December 31 were:

UNDESIGNATED DERIVATIVE IMPACTS

(Dollars in millions)

		Pretax (loss) gain on derivatives recognized in earnings		
		Years ended December 31,		
	Location	2016	2015	2014
Commodity contracts not subject to rate recovery	Operation and Maintenance	$ —	$ —	$ (1)
Commodity contracts subject to rate recovery	Cost of Electric Fuel and purchased power	(53)	(126)	(10)
Total		$ (53)	$ (126)	$ (11)

CONTINGENT FEATURES

Certain of our derivative instruments contain credit limits which vary depending on our credit ratings. Generally, these provisions, if applicable, may reduce our credit limit if a specified credit rating agency reduces our ratings. In certain cases, if our credit ratings were to fall below investment grade, the counterparty to these derivative liability instruments could request immediate payment or demand immediate and ongoing full collateralization.

For SDG&E, the total fair value of this group of derivative instruments in a net liability position is negligible at December 31, 2016 and $5 million at December 31, 2015. At December 31, 2016, if the credit ratings of SDG&E were reduced below investment grade, $3 million of additional assets could be required to be posted as collateral for these derivative contracts.

Some of our derivative contracts contain a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contracts. Such additional assurance, if needed, is not material and is not included in the amounts above.

NOTE 8. FAIR VALUE MEASUREMENTS

Recurring Fair Value Measures

The table below, by level within the fair value hierarchy, sets forth our financial assets and liabilities that were accounted for at fair value on a recurring basis at December 31, 2016 and 2015. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities, and their placement within the fair value hierarchy levels.

The fair value of commodity derivative assets and liabilities is presented in accordance with our netting policy, as we discuss in Note 7 in "Financial Statement Presentation."

The detrmination of fair values, shown in the table below, incorporates various factors, including but not limited to, the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests).

Our finanicial assets and liabilities that were accounted for at fair value on a recurring basis at December 31, 2016 and 2015 in the tables below include the following:

- Nuclear decommissioning trusts reflect the assets of SDG&E's nuclear decommissioning trusts, excluding cash balances. A third party trustee values the trust assets using prices from a pricing service based on a market approach. We validate these prices by comparison to prices from other independent data sources. Equity and certain debt securities are valued using quoted prices listed on nationally recognized securities exchanges or based on closing prices reported in the active market in which the identical security is traded (Level 1). Other debt securities are valued based on yields that are currently available for comparable securities of issuers with similar credit ratings (Level 2).
- For commodity contracts, we primarily use a market approach with market participant assumptions to value these derivatives. Market participant assumptions include those about risk, and the risk inherent in the inputs to the valuation techniques. These inputs can be readily observable, market corroborated, or generally unobservable. We have exchange-traded derivatives that are valued based on quoted prices in active markets for the identical instruments (Level 1). We also may have other commodity derivatives that are valued using industry standard models that consider quoted forward prices for commodities, time value, current market and contractual prices for the underlying instruments, volatility factors, and other relevant economic measures (Level 2). Level 3 recurring items relate to CRRs and long-term, fixed-price electricity positions at SDG&E, as we discuss below in "Level 3 Information."
- Rabbi Trust investments include marketable securities that we value using a market approach based on closing prices reported in the active market in which the identical security is traded (Level 1). These investments in marketable securities were negligible at both December 31, 2016 and 2015.

There were no transfers into or out of Level 1, Level 2 or Level 3 for during the periods presented.

RECURRING FAIR VALUE MEASURES
(Dollars in millions)

	Fair value at December 31, 2016				
	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Nuclear decommissioning trusts:					
Equity securities	$ 508	—	—	—	$ 508
Debt securities:					

	Level 1	Level 2	Level 3	Netting(1)	Total
Debt securities issued by the U.S. Treasury and other					
U.S. government corporations and agencies	36	16	—	—	52
Municipal bonds	—	206	—	—	206
Other securities	—	141	—	—	141
Total debt securities	36	363	—	—	399
Total nuclear decommissioning trusts(2)	544	363	—	—	907
Commodity contracts not subject to rate recovery	—	—	—	1	1
Commodity contracts subject to rate recovery	1	2	96	30	129
Total	$ 545	$ 365	$ 96	$ 31	$ 1,037
Liabilities:					
Commodity contracts subject to rate recovery	17	7	170	(16)	178
Total	$ 17	$ 7	$ 170	$ (16)	$ 178

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and with cash collateral, as well as cash collateral not offset.

(2) Excludes cash balances and cash equivalents.

RECURRING FAIR VALUE MEASURES

(Dollars in millions)

	Fair value at December 31, 2015				
	Level 1	Level 2	Level 3	Netting(1)	Total
Assets:					
Nuclear decommissioning trusts:					
Equity securities	$ 619	$ —	$ —	$ —	$ 619
Debt securities:					
Debt securities issued by the U.S. Treasury and other					
U.S. government corporations and agencies	47	44	—	—	91

Municipal bonds	—	156	—	—	156
Other securities	—	182	—	—	182
Total debt securities	47	382	—	—	429
Total nuclear decommissioning trusts(2)	666	382	—		1,048
Commodity contracts not subject to rate recovery	—	—	—	1	1
Commodity contracts subject to rate recovery	—	—	72	27	99
Total	$ 666	$ 382	$ 72	$ 28	$ 1,148
Liabilities:					
Commodity contracts not subject to rate recovery	1	—	—	(1)	—
Commodity contracts subject to rate recovery	—	67	53	(54)	66
Total	$ 1	$ 67	$ 53	$ (55)	$ 66

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and with cash collateral, as well as cash collateral not offset.

(2) Excludes cash balances and cash equivalents.

Level 3 Information

The following table sets forth reconciliations of changes in the fair value of CRRs and long-term, fixed-price electricity positions classified as Level 3 in the fair value hierarchy:

LEVEL 3 RECONCILIATIONS

(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
Balance at January 1	$ 19	$ 107	$ 99
Realized and unrealized (losses) gains	(120)	(134)	15
Allocated transmission instruments	8	12	19
Settlements	19	34	(26)
Balance at December 31	$ (74)	$ 19	$ 107
Change in unrealized (losses) gains relating to instruments still held at December 31	$ (101)	$ (27)	$ 8

Our Energy and Fuel Procurement department, in conjunction with the finance group, is responsible for determining the appropriate fair value methodologies used to value and classify CRRs and long-term, fixed-price electricity positions on an ongoing basis. Inputs used to determine the fair value of CRRs and fixed-price electricity positions are reviewed and compared with market conditions to determine reasonableness. We expect all costs related to these instruments to be recoverable through customer rates. As such, there is no impact to earnings from changes in the fair value of these instruments.

CRRs are recorded at fair value based almost entirely on the most current auction prices published by the California ISO, an objective source. Annual auction prices are published once a year, typically in the middle of November, and remain in effect for the following year. The impact associated with discounting is negligible. Because these auction prices are a less observable input, these instruments are classified as Level 3. The fair value of these instruments is derived from auction price differences between two locations. From January 1, 2016 to December 31, 2016, the auction prices ranged from $(24) per MWh to $10 per MWh at a given location, and from January 1, 2015 to December 31, 2015, the auction prices ranged from $(16) per MWh to $8 per MWh at a given location. Positive values between two locations represent expected future reductions in congestion costs, whereas negative values between two locations represent expected future charges. Valuation of our CRRs is sensitive to a change in auction price. If auction prices at one location increase (decrease) relative to another location, this could result in a higher (lower) fair value measurement. We summarize CRR volumes in Note 7.

Long-term, fixed-price electricity positions that are valued using significant unobservable data are classified as Level 3 because the contract terms relate to a delivery location or tenor for which observable market rate information is not available. The fair value of the net electricity positions classified as Level 3 is derived from a discounted cash flow model using market electricity forward price inputs. At December 31, 2016, these inputs range from $17.40 per MWh to $56.67 per MWh. A significant increase or decrease in market electricity forward prices would result in a significantly higher or lower fair value, respectively. We summarize long-term, fixed-price electricity position volumes in Note 7.

Realized gains and losses associated with CRRs and long-term electricity positions, which are recoverable in rates, are recorded in Cost of Electric Fuel and Purchased Power on the Statement of Operations. Unrealized gains and losses are recorded as regulatory assets and liabilities, and therefore also do not affect earnings.

Fair Value of Financial Instruments

The fair values of certain of our financial instruments (cash, temporary investments, accounts and notes receivable, short-term due to/from unconsolidated affiliates, dividends and accounts payable, short-term debt and customer deposits) approximate their carrying amounts because of the short-term nature of these instruments. Investments in life insurance contracts that we hold in support of our Supplemental Executive Retirement, Cash Balance Restoration and Deferred Compensation Plans are carried at cash surrender values, which represent the amount of cash that could be realized under the contracts. The following table provides the carrying amounts and fair values of certain other financial instruments that are not recorded at fair value on the Balance Sheet at December 31, 2016 and 2015:

FAIR VALUE OF FINANCIAL INSTRUMENTS
(Dollars in millions)

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 4,349	$ —	$ 4,727	$ —	$ 4,727
	December 31, 2015				
		Fair Value			

	Carrying Amount	Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 3,989	$ —	$ 4,355	$ —	$ 4,355

(1) Before reductions for unamortized discount and debt issuance costs of $43 million and $41 million at December 31, 2016 and 2015, respectively, and excluding capital lease obligations of $632 million and $671 million at December 31, 2016 and 2015, respectively.

We determine the fair value of certain long-term amounts due from unconsolidated affiliates and long-term debt based on a market approach using quoted market prices for identical or similar securities in thinly-traded markets (Level 2). We value other long-term debt using an income approach based on the present value of estimated future cash flows discounted at rates available for similar securities (Level 3).

We provide the fair values for the securities held in the nuclear decommissioning trust funds related to SONGS in Note 10.

NOTE 9. PREFERRED STOCK

SDG&E is authorized to issue up to 45 million shares of preferred stock. At December 31, 2016 and 2015, SDG&E has no preferred stock outstanding. The rights, preferences, privileges and restrictions for any new series of preferred stock would be established by our board of directors at the time of issuance.

NOTE 10. SAN ONOFRE NUCLEAR GENERATING STATION (SONGS)

SDG&E has a 20-percent ownership interest in SONGS, a nuclear generating facility near San Clemente, California, which ceased operations in June 2013. On June 6, 2013, after an extended outage beginning in 2012, Southern California Edison Company (Edison), the majority owner and operator of SONGS, notified SDG&E that it had reached a decision to permanently retire SONGS and seek approval from the Nuclear Regulatory Commission (NRC) to start the decommissioning activities for the entire facility. SONGS is subject to the jurisdiction of the NRC and the CPUC.

SDG&E, and each of the other owners, holds its undivided interest as a tenant in common in the property. Each owner is responsible for financing its share of expenses and capital expenditures. SDG&E's share of operating expenses is included in the Statement of Operations.

SONGS Steam Generator Replacement Project

As part part of the Steam Generator Replacement Project (SGRP), the steam generators were replaced in SONGS Units 2 and 3, and the Units returned to service in 2010 and 2011, respectively. Both Units were shut down in early 2012 after a water leak occurred in the Unit 3 steam generator. Edison concluded that the leak was due to unexpected wear from tube-to-tube contact. At the time the leak was identified, Edison also inspected and tested Unit 2 and subsequently found unexpected tube wear in Unit 2's steam generator. These issues with the steam generators ultimately resulted in Edison's decision to permanently retire SONGS.

The replacement steam generators were designed and provided by Mitsubishi Heavy Industries, Ltd., Mitsubishi Nuclear Energy

Systems, Inc., and Mitsubishi Heavy Industries America, Inc. (collectively MHI). In July 2013, SDG&E filed a lawsuit against MHI seeking to recover damages SDG&E has incurred and will incur related to the design defects in the steam generators. In October 2013, Edison instituted arbitration proceedings against MHI seeking damages as well. SDG&E is participating in the arbitration as a claimant and respondent. The arbitration hearing concluded in April 2016, and a decision could be reached in the first half of 2017. We discuss these proceedings in Note 15.

Settlement Agreement to Resolve the CPUC's Order Instituting Investigation (OII) into the SONGS Outage (SONGS OII)

In Novemeber 2012, in response to the outage, the CPUC issued the SONGS OII, which was intended to determine the ultimate recovery of the investment in SONGS and the costs incurred since the commencement of this outage.

In November 2014, the CPUC issued a final decision approving an Amended and Restated Settlement Agreement (Amended Settlement Agreement) in the SONGS OII proceeding executed by SDG&E along with Edison, The Utility Reform Network (TURN), the CPUC Office of Ratepayer Advocates (ORA) and two other intervenors who joined an earlier settlement agreement. The Amended Settlement Agreement does not affect ongoing or future proceedings before the NRC, or litigation or arbitration related to potential future recoveries from third parties (except for the allocation to ratepayers of any recoveries addressed in the final decision) or proceedings addressing decommissioning activities and costs.

The Amended Settlement Agreement provides for various disallowances, refunds and rate recoveries, including authorizing SDG&E to recover in rates its remaining investment in SONGS, including base plant and construction work in progress, but excluding its investment in the SGRP, generally over a ten-year period commencing February 1, 2012, together with a return on investment at a reduced rate equal to:

- SDG&E's weighted average return on debt, plus
- 50 percent of SDG&E's weighted average return on preferred stock, as authorized in the CPUC's Cost of Capital (discussed in Note 14) proceeding then in effect (collectively, SONGS rate of return or SONGS ROR)

This has resulted in a SONGS ROR of 2.35 percent for the period from January 1, 2013 through December 31, 2016, which rate will remain in effect through 2017. The SONGS ROR for future periods will fluctuate based on SDG&E's authorized weighted average returns on debt and preferred stock in effect for those future periods.

In April 2015, a petition for modification was filed with the CPUC by Alliance for Nuclear Responsibility (A4NR), an intervenor in the SONGS OII proceeding, asking the CPUC to set aside its decision approving the Amended Settlement Agreement and reopen the SONGS OII proceeding. In June 2015, TURN, a party to the Amended Settlement Agreement, filed a response supporting the A4NR petition. TURN does not question the merits of the Amended Settlement Agreement, but is concerned that certain allegations regarding Edison raised by A4NR have undermined the public's confidence in the regulatory process.

In August 2015, ORA, also a party to the Amended Settlement Agreement, filed a petition for modification with the CPUC, withdrawing its support for the Amended Settlement Agreement and asking the CPUC to reopen the SONGS OII proceeding. The ORA does not question the merits of the Amended Settlement Agreement, but is concerned with the CPUC's approach toward disclosures concerning Edison *ex parte* communications with the CPUC.

In May 2016, the CPUC issued a ruling reopening the record of the OII to address the issue of whether the Amended Settlement

Agreement is reasonable and in the public interest. In accordance with the ruling, Edison and SDG&E filed separate reports with the CPUC in June 2016 on the Amended Settlement Agreement and the status of its implementation, and filed separate legal briefs in July 2016 asserting that the Amended Settlement Agreement is reasonable and in the public interest.

In December 2016, the CPUC issued a procedural ruling directing parties to the SONGS OII to determine whether an agreement could be reached to modify the Amended Settlement Agreement previously approved by the CPUC to resolve allegations that unreported *ex parte* communications between Edison and the CPUC resulted in an unfair advantage at the time the settlement agreement was negotiated. The ruling directs the parties to consider various issues, including the division between ratepayers and shareholders of any future MHI arbitration award. If no agreement is reached by April 28, 2017, the CPUC will consider other options including entertaining additional testimony, hearings and briefs.

There is no assurance that the Amended Settlement Agreement will not be renegotiated, modified or set aside as a result of these proceedings, which could result in a substantial reduction in our expected recovery and have a material adverse effect on SDG&E's results of operations, financial condition and cash flows.

Accounting and Financial Impacts

Through December 31, 2016, the cumulative after-tax loss from plant closure recorded by SDG&E is $125 million, including a reduction in the after-tax loss of $13 million recorded in the first quarter of 2015 based on the CPUC's approval in March 2015 of SDG&E's compliance filing and establishment of the SONGS settlement revenue requirement, and a reduction in the after-tax loss of $2 million based on a settlement with Nuclear Electric Insurance Limited in the fourth quarter of 2015, as we discuss below. In 2014, SDG&E recorded a $21 million after-tax increase to the loss, including $12 million based on a compliance filing regarding SDG&E's annual revenue requirement and the timing of refunds to ratepayers.

The remaining regulatory asset for the expected recovery of SONGS costs, consistent with the Amended Settlement Agreement, is $183 million ($31 million current and $152 million long-term) at December 31, 2016. The amortization period prescribed for the regulatory asset is 10 years, which commenced in January 2015 following the CPUC's final decision approving the Amended Settlement Agreement in November 2014.

A decision in the MHI arbitration could be reached in the first half of 2017. Under the Amended Settlement Agreement, SDG&E's 20-percent share of any proceeds from the MHI arbitration, net of legal costs, must be equally divided between SDG&E shareholders and ratepayers. As we discuss above, there is no assurance that the Amended Settlement Agreement will not be modified as it pertains to the MHI arbitration proceedings by the ongoing CPUC OII proceeding. Accordingly, determination of the shareholder component of MHI arbitration proceeds, if any, may be suspended until resolution of the SONGS OII proceeding.

Settlement with Nuclear Electric Insurance Limited (NEIL)

As we discuss in Note 15, NEIL insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks. In October 2015, the SONGS co-owners (Edison, SDG&E and the City of Riverside) reached an agreement with NEIL to resolve all of SONGS' insurance claims arising out of the failures of the replacement steam generators for a total payment by NEIL of $400 million, SDG&E's share of which was $80 million. Pursuant to the terms of the SONGS OII Amended Settlement Agreement, after reimbursement of legal fees and a 5-percent allocation to shareholders, the net proceeds of $75 million were allocated to ratepayers through the Energy Resource Recovery Account.

NRC Proceedings

In December 2013, Edison received a final NRC Inspection Report that identified a violation for the failure to verify the adequacy of the thermal-hydraulic and flow-induced vibration design of the Unit 3 replacement steam generator. In January 2014, Edison provided a response to the NRC Inspection Report stating that MHI, as contracted by Edison to prepare the SONGS replacement steam generator design, was the party responsible for validating the design of the steam generators.

In addition, the NRC issued an Inspection Report to MHI containing a Notice of Nonconformance for its flawed computer modeling in the design of the replacement steam generators.

Because SONGS has ceased operation, NRC inspection oversight of SONGS will now be continued through the NRC's Decommissioning Power Reactor Inspection Program to verify that decommissioning activities are being conducted safely, that spent fuel is safely stored onsite or transferred to another licensed location, and that the site operations and licensee termination activities conform to applicable regulatory requirements, licensee commitments and management controls.

Nuclear Decommissioning and Funding

As a result of Edison's decision to permanently retire SONGS Units 2 and 3, Edison has begun the decommissioning phase of the plant. The process of decommissioning a nuclear power plant is governed by the regulations of various governmental and other agencies, including but not limited to, those of the NRC, the U.S. Department of the Navy (the land owner) and the CPUC. The NRC regulations generally categorize the decommissioning activities into three phases: initial activities, major decommissioning and storage activities, and license termination. Initial activities include providing notice of permanent cessation of operations and notice of permanent removal of fuel from the reactor vessels, which were provided by Edison in 2013. Within two years after the cessation of operations, the licensee (Edison) must submit a post-shutdown decommissioning activities report, an irradiated fuel management plan and a site-specific decommissioning cost estimate. Edison submitted each of these items to the NRC in September 2014.

In December 2016, Edison announced that, following a 10-month competitive bid process, it had contracted with a joint venture of AECOM and EnergySolutions (known as SONGS Decommissioning Solutions) as the general contractor to complete the dismantlement of SONGS. The majority of the dismantlement work is expected to take 10 years. SDG&E is responsible for 20 percent of the total contract price.

In accordance with state and federal requirements and regulations, SDG&E has assets held in trusts, referred to as the Nuclear Decommissioning Trusts (NDT), to fund decommissioning costs for SONGS Units 1, 2 and 3. Decommissioning of Unit 1, removed from service in 1992, is largely complete. The remaining work for Unit 1 will be done once Units 2 and 3 are dismantled. At December 31, 2016, the fair value of SDG&E's NDT assets was $1.0 billion. Except for the use of funds for the planning of decommissioning activities or NDT administrative costs, CPUC approval is required for SDG&E to access the NDT assets to fund SONGS decommissioning costs for Units 2 and 3.

In April 2016, the CPUC adopted a decision approving a total decommissioning cost estimate for SONGS Units 2 and 3 of $4.4 billion (in 2014 dollars), of which SDG&E's share is $899 million. The decision also approves an annual advice letter request process for

SDG&E to request trust fund disbursements for decommissioning costs based on a forecast for 2016 and thereafter. Disbursements from the trust will then be made up to this annual forecast amount as decommissioning expenses are incurred. To the extent actual expenses are consistent with forecasts, this arrangement will generally result in the utilization of nuclear decommissioning trust funds to support decommissioning, reducing the need to temporarily fund such costs with working capital. Certain spent fuel management costs, described below, continue to be temporarily funded with working capital. All disbursements will be subject to future refund until a reasonableness review of the actual decommissioning costs is conducted, which would be no less frequently than every three years.

SDG&E has received authorization from the CPUC to access trust funds for SONGS decommissioning costs of up to $218 million for 2013 through 2016. The $218 million includes $37 million related to spent fuel management costs. In April 2016, Edison, acting for itself and on behalf of SDG&E, entered into a settlement agreement with the U.S. Department of Energy (DOE) to resolve the claims against the DOE related to the spent fuel management costs incurred through 2013. The settlement agreement sets forth an administrative procedure for the submission of claims for costs incurred from 2014 through 2016, which provides for arbitration if the settlement process is unsuccessful. Edison, acting for itself and SDG&E, submitted claims for spent fuel management costs incurred during 2014 and 2015 in September 2016. Claims for spent fuel management costs incurred during 2016 must be submitted by September 30, 2017. SDG&E is not guaranteed recovery of its claims for 2014-2016; however, SDG&E anticipates that the claims for costs incurred in 2014 and 2015 will be resolved during 2017, and the claims for costs incurred in 2016 will be resolved during 2018.

In December 2016, the IRS and the U.S. Department of the Treasury issued proposed regulations that clarify the definition of “nuclear decommissioning costs,” which are costs that may be paid for or reimbursed from a qualified fund. The proposed regulations state that costs related to the construction and maintenance of independent spent fuel management installations are included in the definition of “nuclear decommissioning costs.” The proposed regulations will be effective prospectively once they are finalized; however, the IRS has stated that it will not challenge taxpayer positions consistent with the proposed regulations for taxable years ending on or after the date the proposed regulations were issued. SDG&E is working with outside counsel to clarify with the IRS some of the provisions in the proposed regulations so as to confirm that the proposed regulations will allow SDG&E to access the trust funds for reimbursement or payment of the spent fuel management costs that were or will be incurred in 2016 and subsequent years.

In December 2016, SDG&E filed an advice letter with the CPUC requesting authority to withdraw up to $84 million for 2017 SONGS Units 2 and 3 costs (forecasted). The CPUC approved SDG&E’s request in February 2017, which allows SDG&E to withdraw from the funds as decommissioning costs are incurred.

Nuclear Decomissioning Trusts

The amounts collected in rates for SONGS’ decommissioning are invested in the NDT, which is comprised of externally managed trust funds. Amounts held by the trusts are invested in accordance with CPUC regulations. These trusts are shown on SDG&E’s Balance Sheet at fair value with the offsetting credits recorded in Regulatory Liabilities Arising from Removal Obligations.

The following table shows the fair values and gross unrealized gains and losses for the securities held in the NDT. We provide additional fair value disclosures for the NDT in Note 8.

NUCLEAR DECOMMISSIONING TRUSTS *(Dollars in millions)*				
	Cost	Gross unrealized	Gross unrealized	Estimated fair

		gains	losses	value
At December 31, 2016:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies(1)	$ 52	$ —	$ —	$ 52
Municipal bonds(2)	203	4	(1)	206
Other securities(3)	141	2	(2)	141
Total debt securities	396	6	(3)	399
Equity securities	143	366	(1)	508
Cash and cash equivalents	119	—	—	119
Total	$ 658	$ 372	$ (4)	$ 1,026
At December 31, 2015:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	$ 89	$ 2	$ —	$ 91
Municipal bonds	148	8	—	156
Other securities	194	1	(13)	182
Total debt securities	431	11	(13)	429
Equity securities	214	412	(7)	619
Cash and cash equivalents	15	—	—	15
Total	$ 660	$ 423	$ (20)	$ 1,063

(1) Maturity dates are 2017-2047.

(2) Maturity dates are 2017-2115.

(3) Maturity dates are 2017-2111.

The following table shows the proceeds from sales of securities in the NDT and gross realized gains and losses on those sales.

SALES OF SECURITIES
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
Proceeds from sales(1)	$ 1,134	$ 577	$ 601
Gross realized gains	111	29	11
Gross realized losses	(29)	(15)	(11)

(1) Excludes securities that are held to maturity.

Net unrealized gains (losses) are included in Regulatory Liabilities Arising from Removal Obligations on SDG&E's Balance Sheet. We determine the cost of securities in the trusts on the basis of specific identification. In 2016, sale and purchase activities in our NDT increased significantly compared to prior years as a result of a change to our asset allocation to reduce our equity volatility, lower our duration risk, and increase exposure to municipal bonds and intermediate credit. This shift in our asset mix is intended to reduce the overall risk profile of the NDT, as we are in the decommissioning stage at the plant.

Asset Retirement Obligation and Spent Nuclear Fuel

SDG&E's asset retirement obligation related to decommissioning costs for the SONGS units was $637 million at December 31, 2016. That amount includes the cost to decommission Units 2 and 3, and the remaining cost to complete the decommissioning of Unit 1, which is substantially complete. The asset retirement obligation at December 31, 2016 is based on a CPUC-approved cost study prepared in 2014 that reflects the acceleration of the start of decommissioning Units 2 and 3 as a result of the early closure of the plant. An updated cost study for Unit 1 is pending approval by the CPUC. SDG&E's share of total decommissioning costs in 2016 dollars is approximately $989 million.

Spent nuclear fuel from SONGS is stored on-site in an Independent Spent Fuel Storage Installation (ISFSI) licensed by the NRC or temporarily in spent fuel pools. The ISFSI will be decommissioned after a spent fuel storage facility becomes available and the DOE removes the spent fuel from the site. Until then, SONGS owners are responsible for interim storage of spent nuclear fuel at SONGS.

NOTE 11. REGULATORY MATTERS

REGULATORY BALANCING ACCOUNTS

SDG&E maintains regulatory balancing accounts. Over- and undercollected regulatory balancing accounts reflect the difference between customer billings and recorded or CPUC-authorized costs, including commodity costs. Amounts in the balancing accounts are recoverable (receivable) or refundable (payable) in future rates, subject to CPUC approval. Balancing account treatment eliminates the impact on earnings from variances in the covered costs from authorized amounts. Absent balancing account treatment, variations in the cost of fuel supply and certain operating and maintenance costs from amounts approved by the CPUC would increase volatility in utility earnings.

The following table summarizes our regulatory balancing accounts at December 31.

SUMMARY OF REGULATORY BALANCING ACCOUNTS AT DECEMBER 31
(Dollars in millions)

	2016	2015
Current:		
Overcollected	$ (301)	$ (345)
Undercollected	560	652
Net current receivable (payable)	259	307
Noncurrent:		
Undercollected	—	—
Net noncurrent receivable (payable)	—	—
Total net receivable (payable)	$ 259	$ 307

REGULATORY ASSETS AND LIABILITIES

We show the details of regulatory assets and liabilities in the following table, and discuss each of them separately below.

REGULATORY ASSETS (LIABILITIES)
(Dollars in millions)

	December 31, 2016	December 31, 2015
Fixed-price contracts and other derivatives	$ 141	$ 99
Costs related to SONGS plant closure(1)	183	257
Costs related to wildfire litigation	353	362
Deferred taxes recoverable in rates	1,014	914
Pension and other postretirement benefit plan obligations	210	180
Removal obligations(2)	(1,725)	(1,629)
Unamortized loss on reacquired debt	12	12
Environmental costs	48	16
Legacy meters(1)	16	32
Sunrise Powerlink fire mitigation	118	117
Other	(2)	9
Total	$ 368	$ 369

(1) Regulatory assets earning a rate of return.

(2) Represents cumulative amounts collected in rates for future nonlegal asset removal costs.

NET REGULATORY ASSETS (LIABILITIES) AS PRESENTED ON THE BALANCE SHEET
(Dollars in millions)

	December 31, 2016	December 31, 2015
Current regulatory assets	$ 81	$ 107
Noncurrent regulatory assets	2012	1891
Current regulatory liabilities	—	—

Noncurrent regulatory liabilities	(1,725)	(1,629)
Total	$ 368	$ 369

In the tables above:

- Regulated assets arising from fixed-price contracts and other derivatives are offset by corresponding liabilities arising from purchased power and natural gas commodity and transportation contracts. The regulatory asset is increased/decreased based on changes in the fair market value of the contracts. It is also reduced as payments are made for commodities and services under these contracts.
- Regulatory assets arising from the SONGS plant closure are associated with SDG&E's investment in SONGS as of the plant closure date and the cost of operations since Units 2 and 3 were taken offline, as we discuss further in Note 13.
- Regulatory assets recorded to the Wildfire Expense Memorandum Account (WEMA) arising from CPUC-related costs for wildfire litigation are costs in excess of liability insurance coverage and amounts recovered from third parties, and are subject to CPUC review for reasonableness and assessment of SDG&E's prudence surrounding the settlement of claims in connection with the 2007 wildfires. We discuss the 2007 wildfires in Note 15 in "SDG&E – 2007 Wildfire Litigation."
- Deferred taxes recoverable in rates are based on current regulatory ratemaking and income tax laws. SDG&E expects to recover net regulatory assets related to deferred income taxes over the lives of the assets that give rise to the accumulated deferred income tax liabilities. Regulatory assets include certain income tax benefits associated with flow-through repair allowance deductions, which we discuss further below.
- Regulatory assets/liabilities related to pension and other postretirement benefit plan obligations are offset by corresponding liabilities/assets and are being recovered in rates as the plans are funded.
- Regulatory assets related to unamortized losses on reacquired debt are recovered over the remaining amortization periods of the losses on reacquired debt. These periods range from 1 year to 11 years.
- Regulatory assets related to environmental costs represent the portion of our environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. We expect this amount to be recovered in future rates as expenditures are made. We discuss environmental issues further in Note 12.
- The regulatory asset related to the legacy meters removed from service and replaced under the Smart Meter Program is their undepreciated value. SDG&E is recovering this asset over a remaining 1-year period in rate base.
- The regulatory asset related to Sunrise Powerlink fire mitigation is offset by a corresponding liability for the funding of a trust to cover the mitigation costs. SDG&E expects to recover the regulatory asset in rates as the trust is funded over a remaining 53-year period. We discuss the trust further in Note 15.
- The regulatory asset related to workers' compensation represents accrued costs for future claims that will be recovered from customers in future rates as expenditures are made.
- Amortization expense on regulatory assets for the years ended December 31, 2016, 2015 and 2014 was $63 million, $60 million and $18 million, respectively.

CALIFORNIA UTILITIES MATTERS

CPUC General Rate Case (GRC)

The CPUC uses a general rate case proceeding to set sufficient rates to allow SDG&E to recover their reasonable cost of operations and maintenance and to provide the opportunity to realize their authorized rates of return on their investment.

In November 2014, we filed our 2016 General Rate Case (2016 GRC) application to establish our authorized 2016 revenue requirement and the ratemaking mechanisms by which the requirement would change on an annual basis until the next general rate case proceeding.

In June 2016, the CPUC issued a final decision in the 2016 GRC. The final decision (2016 GRC FD) adopted a 2016 revenue requirement of $1.791 billion for SDG&E. The 2016 GRC FD also required certain refunds to be paid to customers and establishes a two-way income tax expense memorandum account, each discussed below.

In 2016 GRC FD also adopted subsequent annual escalation of the adopted revenue requirement by 3.5 percent for years 2017 and 2018 and continuation of the Z-Factor mechanism for qualifying cost recovery. The Z-Factor mechanism allows SDG&E to seek cost recovery of significant cost increases, under certain unforeseen circumstances, incurred between GRC filings, subject to a $5 million deductible per event. Also, the 2016 GRC FD denied a separate request for a four-year GRC period and instead adopted a three-year GRC period (through 2018).

The 2016 GRC FD is effective retroactive to January 1, 2016, SDG&E recorded the retroactive impact in the second quarter of 2016. The adopted revenue requirement associated with the seven-month period through July 2016 will be recovered in rates over a 17-month period, beginning August 2016 through December 2017. At December 31, 2016, balancing account related to the adoption of the revenue requirement was $20 million.

The 2016 GRC FD results in certain accounting impacts associated with flow-through income tax repairs deductions. In general, the 2016 GRC FD considers that the income tax benefits obtained from income tax repairs deductions exceeded amounts forecasted by SDG&E from 2011 to 2015, and that they were attributed to shareholders during that time. The 2016 GRC FD reallocates the economic benefit of this tax deduction forecasting difference to ratepayers. Accordingly, revenues corresponding to income tax repair deductions that exceeded forecasted amounts relating to 2015, which have been tracked in memorandum accounts, are ordered to be refunded to customers. The 2015 estimated amounts in the memorandum accounts totaled $37 million for SDG&E. Pursuant to this refund requirement, SDG&E recorded regulatory liabilities for this amount, resulting in after-tax charges to earnings of $22 million in the second quarter of 2016 (summarized below). In addition, the 2016 GRC FD reduced rate base by $55 million. The corresponding reductions in the 2016 revenue requirement will be $7 million (which reductions are included in the adopted 2016 revenue requirement amounts described above). The rate base reductions reallocate to ratepayers the economic benefits associated with tax repair deductions that were previously provided to the shareholders for the period of 2011-2014. The rate base reductions do not result in an impairment of any of our reported assets, but will impact our revenues and earnings prospectively.

The 2016 GRC FD also requires us to notify the CPUC if the 2012-2015 repairs deductions estimated in this GRC are different from the actual repairs deductions. SDG&E recorded regulatory liabilities of $15 million related to 2012-2014, resulting in after-tax charges to earnings for this difference of $9 million in the second quarter of 2016 (summarized below). In the third quarter of 2016, SDG&E completed our 2015 calendar year tax returns, and final tax deductions associated with tax repair benefits to be refunded to ratepayers associated with the 2015 memo account were lower than the amounts estimated in 2015. Accordingly, the amounts to be refunded decreased by $5 million. In October 2016, SDG&E filed a regulatory account update with the CPUC to reflect their final total 2015 repair allowance deductions of $32 million. After recording the related income tax effect and corresponding regulatory revenue adjustments for income tax purposes, there was no net impact to earnings from the adjustments to the 2015 tax repairs deductions recorded in the third quarter of 2016. Accordingly, the earnings impacts in the table below are also the earnings impacts for the year ended December 31, 2016.

Following is a summary of immediate earnings impacts from the 2016 GRC FD:

EARNINGS IMPACTS FROM THE 2016 GRC FD *(Dollars in millions)*		
	Pretax earnings (charge)	After-tax earnings (charge)
Adjustments to revenue related to tax		

repairs deductions:		
2015 memorandum account balance	$ (37)	$ (22)
True-up of 2012-2014 estimates to actuals	(15)	(9)
Total	$ (52)	$ (31)

Finally, the 2016 GRC FD requires the establishment of a two-way income tax expense memorandum account to track any revenue differences resulting from differences between the income tax expense forecasted in the GRC and the income tax expense incurred by SDG&E from 2016 through 2018. The differences tracked are to specifically include tax expense differences relating to:

- Net revenue changes;
- mandatory tax law, tax accounting, tax procedural, or tax policy changes; and
- elective tax law, tax accounting, tax procedural, or tax policy changes.

The account will remain open, and the balance in the account will be reviewed in subsequent GRC proceedings, until the CPUC decides to close the account. In July 2016, to address the implementation of the 2016 GRC FD, SDG&E filed an advice letter to establish a two-way memorandum account to track revenue requirement differences resulting from the differences in the income tax expense forecasted in the GRC proceedings and the income tax expense incurred by them during the GRC period. Starting in the second quarter of 2016, SDG&E is recording liabilities associated with tracking the differences in the income tax expense forecasted in the GRC proceedings and the income tax expense incurred, which for the year ended December 31, 2016 resulted in after-tax charges to earnings of $3 million ($5 million pretax).

CPUC Cost of Capital

A CPUC cost of capital proceeding determines a utility’s authorized capital structure and authorized rate of return on rate base (ROR), which is a weighted average of the authorized returns on debt, preferred stock, and common equity (return on equity or ROE), weighted on a basis consistent with the authorized capital structure. The authorized ROR is the rate that SDG&E is authorized to use in establishing rates to recover the cost of debt and equity used to finance its investment in CPUC-regulated electric distribution and generation as well as natural gas distribution, transmission and storage assets.

A cost of capital proceeding also addresses the automatic cost of capital adjustment mechanism (CCM), which applies market-based benchmarks to determine whether an adjustment to the authorized ROR is required during the interim years between cost of capital proceedings. The market-based benchmark for SDG&E’s CCM is the 12-month average monthly A-rated utility bond index, as published by Moody’s for the 12-month period of October 1st through September 30th (CCM Period) of each calculation year. In the last cost of capital proceeding, SDG&E’s CCM benchmark rate was set at 4.24 percent. If at the end of the CCM Period the monthly average benchmark rate falls outside of the established range of 3.24 percent to 5.24 percent, SDG&E’s authorized ROE would be adjusted, upward or downward, by one-half of the difference between the 12-month average and the benchmark rate. In addition, the authorized recovery rate for SDG&E’s cost of debt and preferred stock would be adjusted to its respective actual weighted average costs, with no change to the authorized capital structure. All three adjustments with the new rate would become effective on January 1st of the following year in which the benchmark range was exceeded. For the twelve-month period ended September 30, 2016, the 12-month average of monthly Moody’s A-rated utility bond index was 4.01 percent, which is within the established range of 3.24 percent and 5.24 percent.

The CCM only applies during the intervening years between scheduled cost of capital proceedings. In the year the cost of capital proceeding is scheduled, the cost of capital proceeding takes precedence over the CCM and will set new rates for the following year.

SDG&E's current CPUC-authorized ROR is 7.79 percent based on its authorized capital structures as follows:

COST OF CAPITAL AND AUTHORIZED RATE STRUCTURE – CPUC			
	Authorized	Authorized rate of	Weighted

	weighting	recovery	authorized ROR
Long-Term Debt	45.25%	5.00%	2.26%
Preferred Stock	2.75%	6.22%	0.17%
Common Equity	52.00%	10.30%	5.36%
	100.00%		7.79%

Under an agreement approved in 2016, the CPUC granted SDG&E an extension of their cost of capital filing deadline to April 2017 and extended the current CCM until the April 2017 filing date. However, in the event the adjustment mechanism is triggered, the utilities agreed that no changes to the current cost of capital would be made under the mechanism.

On February 7, 2017, SDG&E, SoCalGas, Pacific Gas and Electric Company (PG&E) and Edison (collectively, the Joint Investor-Owned Utilities or Joint IOUs), along with the ORA and TURN, entered into a memorandum of understanding and filed a joint petition for modification (PFM) with the CPUC seeking a two-year extension for each of the Joint IOUs to file its next respective cost of capital application, extending the date to file the next cost of capital application from April 2017 to April 2019 for a 2020 test year. In addition to the two-year extension of the deadline to file the next cost of capital application, the memorandum of understanding contains provisions to reduce the ROE for SDG&E from 10.30 percent to 10.20 percent and for SoCalGas from 10.10 percent to 10.05 percent, effective from January 1, 2018 through December 31, 2019. SDG&E’s and SoCalGas’ ratemaking capital structures will remain at the levels shown above until modified, if at all, by a future cost of capital decision by the CPUC. Also, the Joint IOUs will update their cost of capital for actual cost of long-term debt through August 2017 and forecasted cost through 2018, and update preferred stock costs for anticipated issuances (if any) through 2018. The CCM will be in effect to adjust 2019 cost of capital, if necessary. Unless changed by the operation of the CCM, the updated costs of long-term debt and preferred stock (if applicable) and new ROEs will remain in effect through December 31, 2019. The PFM is subject to final approval by the CPUC.

SDG&E MATTERS

FERC Rate Matters and Cost of Capitol

SDG&E files separately with the FERC for its authorized ROE on FERC-regulated electric transmission operations and assets. The Electric Transmission Formula Rate (TO4) settlement agreement, approved by the FERC in May 2014 and in effect through December 31, 2018, established a 10.05 percent ROE. The settlement also established 1) a process whereby rates are determined using a base period of historical costs and a forecast of capital investments and 2) a true-up period similar to balancing account treatment that is designed to provide SDG&E earnings of no more and no less than its actual cost of service including its authorized return on investment. SDG&E will make annual information filings on December 1 of a given year to update rates for the following calendar year. SDG&E also has the right to file for any ROE incentives that might apply under FERC rules. SDG&E’s debt to equity ratio will be set annually based on the actual ratio at the end of each year.

SDG&E’s current estimated FERC ROR is 7.51 percent based on its capital structure as follows:

SDG&E COST OF CAPITAL AND RATE STRUCTURE – FERC

	Weighting	Rate of recovery	Weighted authorized ROR
Long-Term Debt	43.48%	4.21%	1.83%
Common Equity	56.52%	10.05%	5.68%
	100.00%		7.51%

In September 2015, the presiding judge assigned by the FERC to SDG&E's annual TO4 Formula Cycle 2 filing issued an initial decision and an order on summary judgment that authorized SDG&E to recover all of the costs incurred and allocated to SDG&E's FERC-regulated operations, including $23 million of costs associated with the 2007 wildfires, discussed in Note 15. In October 2015, the CPUC filed a request for rehearing of the FERC's September 2015 order, which requested abeyance of SDG&E's request to recover 2007 wildfire damage expenses. In April 2016, the FERC affirmed its finding in the September 2015 order and denied the CPUC's request for rehearing. The FERC decision finalizes SDG&E's base transmission revenue requirement and the recovery of $23 million of wildfire damage expenses allocated to SDG&E's FERC-regulated operations.

NOTE 12. COMMITMENT AND CONTINGENCIES

LEGAL PROCEEDINGS

We accrue losses losses for a legal proceeding when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. However, the uncertainties inherent in legal proceedings make it difficult to estimate with reasonable certainty the costs and effects of resolving these matters. Accordingly, actual costs incurred may differ materially from amounts accrued, may exceed applicable insurance coverage and could materially adversely affect our business, cash flows, results of operations, financial condition and prospects. Unless otherwise indicated, we are unable to estimate reasonably possible losses in excess of any amounts accrued.

At December 31, 2016, accrued liabilities for legal proceedings were $16 million for SDG&. We discuss our policy regarding accrual of legal fees in Note 1.

SDG&E

2007 Wildfire Litigation

In October 2007, San Diego County experienced several catastrophic wildfires. Reports issued by the California Department of Forestry and Fire Protection (Cal Fire) concluded that two of these fires (the Witch and Rice fires) were SDG&E "power line caused" and that a third fire (the Guejito fire) occurred when a wire securing a Cox Communications' fiber optic cable came into contact with an SDG&E power line "causing an arc and starting the fire." A September 2008 staff report issued by the CPUC's Consumer Protection and Safety Division, now known as the Safety and Enforcement Division, reached substantially the same conclusions as the Cal Fire reports, but also contended that the power lines involved in the Witch and Rice fires and the lashing wire involved in the Guejito fire were not properly designed, constructed and maintained.

SDG&E has resolved almost all of the lawsuits associated with the three fires. Only two appeals remain pending after judgment in the trial court. SDG&E does not expect additional plaintiffs to file lawsuits given the applicable statutes of limitation, but could receive additional settlement demands and damage estimates from the remaining plaintiffs until the cases are resolved. SDG&E establishes reserves for the wildfire litigation as information becomes available and amounts are estimable.

SDG&E has concluded that it is probable that it will be permitted to recover in rates a substantial portion of the costs incurred to resolve wildfire claims in excess of its liability insurance coverage and the amounts recovered from third parties. Accordingly, at December 31, 2016, SDG&E has recorded assets of $353 million in Other Regulatory Assets (long-term) on its Balance Sheet ($352 million related to CPUC-regulated operations and $1 million related to FERC-regulated operations). In September 2015, SDG&E filed an application with the CPUC seeking authority to recover these costs in rates over a six- to ten-year period. The requested amount is the net estimated CPUC-related cost incurred by SDG&E after deductions for insurance reimbursement and third party settlement recoveries, and reflects a voluntary 10-percent shareholder contribution applied to the net WEMA balance. In April 2016, the CPUC issued a ruling establishing the scope and schedule for the proceeding, which will be managed in two phases. Phase 1 will address SDG&E's operational and management prudence surrounding the 2007 wildfires. Phase 2 will address whether SDG&E's actions and decision-making in connection with settling legal claims in relation to the wildfires were reasonable. Should SDG&E conclude that recovery in rates is no longer probable, SDG&E will record a charge against earnings at the time such conclusion is reached. If SDG&E had concluded that the recovery of regulatory assets related to CPUC-regulated operations was no longer probable or was less than currently estimated at December 31, 2016, the resulting after-tax charge against earnings would have been up to approximately $208 million. A failure to obtain substantial or full recovery of these costs from customers, or any negative assessment of the likelihood of recovery, would likely have a material adverse effect on SDG&E's results of operations and cash flow.

We discuss how we assess the probability of recovery of our regulatory assets in Note 1.

Lawsuit Against Mitsubishi Heavy Industries, Ltd.

As we discuss in Note 13, on July 18, 2013, SDG&E filed a lawsuit in the Superior Court of California in the County of San Diego against MHI. The lawsuit seeks to recover damages SDG&E has incurred and will incur related to the design defects in the steam generators MHI provided to the SONGS nuclear power plant. The lawsuit asserts a number of causes of action, including fraud, based on the representations MHI made about its qualifications and ability to design generators free from defects of the kind that resulted in the permanent shutdown of the plant and further seeks to set aside the contractual limitation of damages that MHI has asserted. On July 24, 2013, MHI removed the lawsuit to the United States District Court for the Southern District of California and on August 8, 2013, MHI moved to stay the proceeding pending resolution of the dispute resolution process involving MHI and Edison arising from their contract for the purchase and sale of the steam generators. On October 16, 2013, Edison initiated an arbitration proceeding against MHI seeking damages stemming from the failure of the replacement steam generators. In late December 2013, MHI answered and filed a counterclaim against Edison. On March 14, 2014, MHI's motion to stay the United States District Court proceeding was granted with instructions that require the parties to allow SDG&E to participate in the ongoing Edison/MHI arbitration. As a result, SDG&E participated in the arbitration as a claimant and respondent. The arbitration hearing concluded at the end of April 2016. A decision could be reached in the first half of 2017.

Concluded Matters

Rim Rock Wind Farm. In 2011, the CPUC and FERC approved SDG&E's estimated $285 million tax equity investment in a wind farm project and its purchase of renewable energy credits from that project. SDG&E's contractual obligations to both invest in the Rim Rock wind farm and to purchase renewable energy credits from the wind farm under the power purchase agreement were subject to the satisfaction of certain conditions which, if not achieved, would allow SDG&E to terminate the power purchase agreement and not make the investment.

In December 2013, SDG&E and the project developer began litigating claims against each other regarding whether the project developer had timely satisfied all contractual conditions necessary to trigger SDG&E's obligations to invest in the project and purchase renewable energy credits. On February 11, 2016, SDG&E, the project developer and several of the project developer's parent and affiliated entities entered into a settlement agreement, which was approved by the CPUC in July 2016 and all related lawsuits were dismissed. Under the settlement agreement, among other things, the parties agreed to terminate the tax equity investment arrangement, continue the power purchase agreement for the wind farm generation and release all claims against each other, while generally continuing the other elements of the 2011 approved decision. The settlement agreement resulted in a $39 million credit to ratepayers.

Smart Meters Patent Infringement Lawsuit. In October 2011, SDG&E was sued by a Texas design and manufacturing company in Federal District Court, Southern District of California, and later transferred to the Federal District Court, Western District of Oklahoma as part of Multi-District Litigation proceedings, alleging that SDG&E's recently installed smart meters infringed certain patents. The meters were purchased from a third party vendor that has agreed to defend and indemnify SDG&E. The lawsuit sought injunctive relief and recovery of unspecified amounts of damages. The third party vendor has settled the lawsuit without cost to SDG&E, and a dismissal was entered in federal court on July 20, 2016.

CONTRACTUAL COMMITMENTS

Natural Gas Contracts

SoCalGas has the responsibility for procuring natural gas for both SDG&E's and SoCalGas' core customers in a combined portfolio. For the years ended 2009 through 2016, we had no payments under natural gas contracts.

Purchased-Power Contracts

For 2017, SDG&E expects to meet its customer power requirements from the following resource types:

- Long-term contracts: 40 percent (of which 35 percent is provided by renewable energy contracts expiring on various dates through 2041)
- Other SDG&E-owned generation and tolling contracts (including OMEC): 45 percent
- Spot market purchases: 15 percent

At December 31, 2016, the fixed and determinable estimated future minimum payments under long-term purchased-power contracts were

FUTURE MINIMUM PAYMENTS – PURCHASED-POWER CONTRACTS
(Dollars in millions)

2017	$ 563
2018	556
2019	546
2020	487
2021	487
Thereafter	5,865

Total minimum payments (1)	$	8,504

(1) Excludes purchase agreements accounted for as capital leases

Payments on these contracts represent capacity charges and minimum energy and transmission purchases that exceed the minimum commitment. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Total payments under purchased-power contracts were

PAYMENTS UNDER PURCHASED-POWER CONTRACTS
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
SDG&E	$ 752	$ 715	$ 710

Operating Leases

We have operating leases on real and personal property expiring at various dates from 2017 through 2054. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from two percent to five percent at SDG&E. The rentals payable under these leases may increase by a fixed amount each year or by a percentage of a base year, and most leases contain extension options that we could exercise.

We have an operating lease agreement for future acquisitions of fleet vehicles with an aggregate maximum lease limit of $150 million, $125 million of which has been utilized as of December 31, 2016.

Rent expenses for operating leases is as follows:

RENT EXPENSE - OPERATING LEASES
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
SDG&E	$ 28	$ 27	$ 26

At December 31, 2016, the minimum rental commitments payable in future years under all noncancelable operating leases were

FUTURE MINIMUM PAYMENTS – OPERATING LEASES
(Dollars in millions)

2017	$	27
2018		23
2019		22
2020		20
2021		19
Thereafter		71

Total future minimum rental commitments	$	182

Capital Leases

Power Purchase Agreements

We have five (changed from 2015 reported amount) power purchase agreements with peaker plant facilities, one of which went into commercial operation in 2015. All five are accounted for as capital leases. At December 31, 2016, capital lease obligations for these leases, three with a 25-year term, one with a 10-year term, and one with a 9-year term, were valued at $631 million.

In 2015, we entered into a CPUC-approved 25-year power purchase agreement with a peaker plant facility that is currently under construction. Beginning with the initial delivery of the contracted power, scheduled in June 2017, the power purchase agreement will be accounted for as a capital lease.

At December 31, 2016, the future minimum lease payments and present value of the net minimum lease payments under these capital leases for SDG&E were

FUTURE MINIMUM PAYMENTS – POWER PURCHASE AGREEMENTS *(Dollars in millions)*		
2017	$	144
2018		171
2019		434
2020		104
2021		104
Thereafter		1,806
Total minimum lease payments(1)		2,763
Less: estimated executory costs		(517)
Less: interest(2)		(1,115)
Present value of net minimum lease payments(3)	$	1,131

(1) This amount will be recorded over the lives of the leases as Cost of Electric Fuel and Purchased Power on the Statement of Operations. This expense will receive ratemaking treatment consistent with purchased-power costs, which are recovered in rates.

(2) Amount necessary to reduce net minimum lease payments to present value at the inception of the leases.

(3) Includes $43 million in Current Portion of Long-Term Debt and $588 million in Long-Term Debt on the Balance Sheet at December 31, 2016. Of the present value of net minimum lease payments, $500 million will be recorded as a capital lease obligation when construction of the peaker plant facility is completed and delivery of contracted power commences, which is scheduled to occur in June 2017.

The annual amortization charge for the power purchase agreements was $39 million in 2016, $36 million in 2015 and $33 million in 2014. (The 2015/2014 reported amounts changed from the prior year)

In January 2017, we entered into a CPUC-approved 20-year power purchase agreement with a 500-MW intermediate stage power plant facility to be constructed. Upon commercial operation, scheduled in 2018, the power purchase agreement will be accounted for as a capital lease.

Other Capital Leases

The annual depreciation charge for the fleet vehicles and other assets in 2016, 2015 and 2014 was $1 million, $2 million and $2 million, respectively.

Construction and Development Projects

At December 31, 2016, SDG&E has commitments to make future payments of $143 million for construction projects that include

- $80 million for infrastructure improvements for natural gas and electric transmission and distribution operations;
- $49 million for the engineering, material procurement and construction costs primarily associated with the San Luis Rey Synchronous Condenser and Bay Boulevard Substation relocation projects; and
- $14 million related to spent fuel management at SONGS.

SDG&E expects future payments under these contractual commitments to be $59 million in 2017, $44 million in 2018, $17 million in 2019, $12 million in 2020, $3 million in 2021 and $8 million thereafter.

OTHER COMMITMENTS

SDG&E

In connection with the completion of the Sunrise Powerlink project in 2012, the CPUC required that SDG&E establish a fire mitigation fund to minimize the risk of fire as well as reduce the potential wildfire impact on residences and structures near the Sunrise Powerlink. The future payments for these contractual commitments are expected to be approximately $3 million per year, subject to escalation of 2 percent per year, for a remaining 53-year period. At December 31, 2016, the present value of these future payments of $118 million has been recorded as a regulatory asset as the amounts represent a cost that is expected to be recovered from customers in the future, and the related liability was $118 million.

ENVIRONMENTAL ISSUES

Our operations are subject to federal, state and local environmental laws. We also are subject to regulations related to hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. These laws and regulations require that we investigate and correct the effects of the release or disposal of materials at sites associated with our past and our present operations. These sites include those at which we have been identified as a Potentially Responsible Party (PRP) under the federal Superfund laws and similar state laws.

In addition, we are required to obtain numerous governmental permits, licenses and other approvals to construct facilities and operate our businesses. The related costs of environmental monitoring, pollution control equipment, cleanup costs, and emissions fees are significant. Our costs to operate our facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Other Environmental Issues

We generally capitalize the significant costs we incur to mitigate or prevent future environmental contamination or extend the life, increase the capacity, or improve the safety or efficiency of property used in current operations. The following table shows our capital expenditures (including construction work in progress) in order to comply with environmental laws and regulations:

CAPITAL EXPENDITURES FOR ENVIRONMENTAL ISSUES
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
SDG&E	$ 17	$ 24	$ 23

Our costs that relate to current operations or an existing condition caused by past operations are generally recorded as a regulatory asset due to the probability that these costs will be recovered in rates.

The environmental issues currently facing us include (1) investigation and remediation of our manufactured-gas sites, (2) cleanup of third-party waste-disposal sites used by us at sites for which we have been identified as a PRP and (3) mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS.

The table below shows the status at December 31, 2016, of our manufactured-gas sites and the third-party waste-disposal sites for which we have been identified as a PRP:

STATUS OF ENVIRONMENTAL SITES
(Dollars in millions)

	#Sites complete (1)	#Sites in Process
Manufactured-gas sites	3	—
Third-party waste-disposal sites	2	1

We record environmental liabilities at undiscounted amounts when our liability is probable and the costs can be reasonably estimated. In many cases, however, investigations are not yet at a stage where we can determine whether we are liable or, if the liability is probable, to reasonably estimate the amount or range of amounts of the costs. Estimates of our liability are further subject to uncertainties such as the nature and extent of site contamination, evolving cleanup standards and imprecise engineering evaluations. We review our accruals periodically and, as investigations and cleanups proceed, we make adjustments as necessary. The following table shows our accrued liabilities for environmental matters at December 31, 2016:

ACCRUED LIABILITIES FOR ENVIRONMENTAL MATTERS
(Dollars in millions)

	Manufactured-gas sites	Waste disposal sites (PRP)(1)	Former fossil-fueled power plants	Total(2)
SDG&E(3)	$ —	$ 1	$ 1	$ 2

(1) Sites for which we have been identified as a Potentially Responsible Party.

(2) Includes $1 million classified as current liabilities, and $1 million classified as noncurrent liabilities on SDG&E's Balance Sheet.

(3) Does not include SDG&E's liability for SONGS marine mitigation.

We expect to pay the majority of these accruals over the next three years.

In connection with the issuance of operating permits, SDG&E and the other owners of SONGS previously reached an agreement with the California Coastal Commission (CCC) to mitigate the damage to the marine environment caused by the cooling-water discharge from SONGS during its operation. SONGS' early retirement, described in Note 13, does not reduce SDG&E's mitigation obligation. SDG&E's share of the estimated mitigation costs is $89 million, of which $43 million has been incurred through December 31, 2016, and $46 million is accrued for remaining costs through 2050, which is recoverable in rates and included in Deferred Credits and Other Liabilities on SDG&E's Balance Sheet. The requirements for enhanced fish protection and restoration of coastal wetlands for the SONGS mitigation are in process. Work on the artificial reef that was dedicated in 2008 continues. The CCC has stated that it now requires an expansion of the reef because the existing reef may be too small to consistently meet the performance standards. In December 2016, SDG&E and Edison filed a joint application with the CPUC seeking rate recovery of the costs of the reef expansion. SDG&E's share of the reef expansion costs currently forecasted through 2020 is $7 million. A decision in the proceeding is expected by the end of 2017.

NUCLEAR INSURANCE

SDG&E and the other owners of SONGS have insurance to cover claims from nuclear liability incidents arising at SONGS. This insurance provides $375 million in coverage limits, the maximum amount available, including coverage for acts of terrorism. In addition, the Price-Anderson Act provides for up to $13 billion of secondary financial protection (SFP). If a nuclear liability loss occurring at any U.S. licensed/commercial reactor exceeds the $375 million insurance limit, all nuclear reactor owners could be required to contribute to the SFP. SDG&E's contribution would be up to $50.93 million. This amount is subject to an annual maximum of $7.6 million, unless a default occurs by any other SONGS owner. If the SFP is insufficient to cover the liability loss, SDG&E could be subject to an additional assessment.

The SONGS owners, including SDG&E, also have $2.75 billion of nuclear property, decontamination, and debris removal insurance, subject to a $2.5 million deductible for "each and every loss." This insurance coverage is provided through Nuclear Electric Insurance Limited (NEIL). The NEIL policies have specific exclusions and limitations that can result in reduced or eliminated coverage. Insured members as a group are subject to retrospective premium assessments to cover losses sustained by NEIL under all issued policies. SDG&E could be assessed up to $10.4 million of retrospective premiums based on overall member claims. See Note 13 in "Settlement with NEIL" for discussion of an agreement between the SONGS co-owners and NEIL to settle all claims under the NEIL policies associated with the SONGS outage.

The nuclear property insurance program includes an industry aggregate loss limit for non-certified acts of terrorism (as defined by the Terrorism Risk Insurance Act). The industry aggregate loss limit for property claims arising from non-certified acts of terrorism is $3.24 billion. This is the maximum amount that will be paid to insured members who suffer losses or damages from these non-certified terrorist acts.

U.S. DEPARTMENT OF ENERGY NUCLEAR FUEL DISPOSAL

The Nuclear Waste Policy Act of 1982 made the DOE responsible for accepting, transporting, and disposing of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. This delay will lead to increased costs for spent fuel storage. SDG&E will continue to support Edison in its pursuit of claims on behalf of the SONGS co-owners against the DOE for its failure to timely accept the spent nuclear fuel. In April 2016, Edison executed a spent fuel settlement agreement with the DOE for $162 million covering damages incurred from January 1, 2006 through December 31, 2013. In May 2016, Edison refunded SDG&E $32 million for its respective share of the damage award paid. In applying this refund, SDG&E recorded a $23 million reduction to the SONGS regulatory asset, an $8 million reduction of its nuclear decommissioning balancing account and a $1 million reduction in its SONGS operation and maintenance cost balancing account.

In September 2016, Edison filed claims with the DOE for $56 million in spent fuel management costs incurred in 2014 and 2015 on behalf of the SONGS co-owners under the terms of the 2016 spent fuel settlement agreement. SDG&E's respective share of the claim is $11 million. It is unclear whether the claim will be resolved through settlement or arbitration, when resolution is expected, and whether Edison will receive an award for the full claim amount.

In October 2015, the CCC approved Edison's application for the proposed expansion of an ISFSI at SONGS. The ISFSI expansion began construction in 2016, will be fully loaded with spent fuel by 2019, and will operate until 2049, when it is assumed that the DOE will have taken custody of all the SONGS spent fuel. The ISFSI would then be decommissioned, and the site restored to its original environmental state.

CONCENTRATION OF CREDIT RISK

We maintain credit policies and systems to manage our overall credit risk. These policies include an evaluation of potential counterparties' financial condition and an assignment of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry. We grant credit to utility customers and counterparties, substantially all of whom are located in our service territory, which covers all of San Diego County and an adjacent portion of Orange.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(11,998,026)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		4,157,712		
4	Total (lines 2 and 3)		4,157,712		
5	Balance of Account 219 at End of Preceding Quarter/Year		(7,840,314)		
6	Balance of Account 219 at Beginning of Current Year		(7,840,314)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		361,249		
9	Total (lines 7 and 8)		361,249		
10	Balance of Account 219 at End of Current Quarter/Year		(7,479,065)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1to 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			(11,998,026)		
2					
3			4,157,712		
4			4,157,712	584,687,607	588,845,319
5			(7,840,314)		
6			(7,840,314)		
7					
8			361,249		
9			361,249	569,569,312	569,930,561
10			(7,479,065)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	15,587,115,054	12,656,886,295
4	Property Under Capital Leases	873,554,074	852,823,281
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	16,460,669,128	13,509,709,576
9	Leased to Others	85,194,000	85,194,000
10	Held for Future Use	11,307,728	11,307,728
11	Construction Work in Progress	1,307,453,482	989,342,926
12	Acquisition Adjustments	3,750,721	3,750,721
13	Total Utility Plant (8 thru 12)	17,868,375,059	14,599,304,951
14	Accum Prov for Depr, Amort, & Depl	5,810,907,185	4,514,185,826
15	Net Utility Plant (13 less 14)	12,057,467,874	10,085,119,125
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,147,931,202	4,132,862,506
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	647,464,698	365,812,035
22	Total In Service (18 thru 21)	5,795,395,900	4,498,674,541
23	Leased to Others		
24	Depreciation	14,261,044	14,261,044
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	14,261,044	14,261,044
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	1,250,241	1,250,241
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,810,907,185	4,514,185,826

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,896,992,638				1,033,236,121	3
				20,730,793	4
					5
					6
					7
1,896,992,638				1,053,966,914	8
					9
					10
191,606,677				126,503,879	11
					12
2,088,599,315				1,180,470,793	13
749,514,263				547,207,096	14
1,339,085,052				633,263,697	15
					16
					17
741,143,625				273,925,071	18
					19
					20
8,370,638				273,282,025	21
749,514,263				547,207,096	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
749,514,263				547,207,096	33

Schedule Page: 200 Line No.: 4 Column: b

Description	Capital leases	ITD Depreciation	Capital lease obligations
Otay Mesa Energy Center (OMEC)	595,400,000	(203,285,531)	392,114,469
Orange Grove	123,238,342	(8,368,262)	114,870,080
El Cajon Energy	59,751,923	(7,136,267)	52,615,656
Escondido	59,549,016	(2,541,519)	57,007,497
Fleet	20,730,793	(20,361,830)	368,963
Yuma	14,884,000	(142,104)	14,741,896
	873,554,074	(241,835,513)	631,718,561

Schedule Page: 200 Line No.: 14 Column: b

Reclassification as of 12/2016 Accum. Provision for Depreciation & Amortization for Ratemaking

Accumulated Provision for Depreciation & Amortization Classified under FERC Seven Factor Test In Accordance with Guidelines in FERC Order 888

	Accumulated Provision
Electric	
Intangible Plant	82,952,173
Steam Production Plant	214,985,087
Other Production Plant	197,262,156
Transmission Plant	945,358,193
Distribution Plant	2,685,181,195
General Plant	138,237,147
Ratemaking Electric	4,263,975,951
Nuclear Decommissioning	1,025,383,767
ASC 410 (FAS 143 and FIN 47) - Electric	(1,028,764,367)
Capital Leases A/D	221,473,683
Leased to Others- Citizens A/D	14,261,044
Cuyamaca Permanent Adjustment	17,855,747
Total Electric	4,514,185,825
Ratemaking Gas	958,934,597
FIN 47 - Gas	(209,420,334)
Total Gas	749,514,263
Ratemaking Common	524,604,556
FIN 47 - Common	2,240,710
Fleet Capital Lease A/D	20,361,830
Total Common	547,207,096
Total Accumulated Provision EOQ 12/2016	5,810,907,184

Total 13-Month Average Accum. Provision as of 12/31/2016 -Steam Production	204,743,799
Total 13-Month Average Accum. Provision as of 12/31/2016 -Nuclear Production	-
Total 13-Month Average Accum. Provision as of 12/31/2016 -Other Production	188,005,078
Total 13-Month Average Accum. Provision as of 12/31/2016 -Transmission Plant	897,504,061

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
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			9
			10
			11
			12
			13
			14
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			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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		
3	(302) Franchises and Consents	222,841	
4	(303) Miscellaneous Intangible Plant	144,186,514	11,092,524
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	144,409,355	11,092,524
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	14,526,518	
9	(311) Structures and Improvements	95,217,764	254,277
10	(312) Boiler Plant Equipment	166,576,622	1,573,997
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	131,184,022	7,092,502
13	(315) Accessory Electric Equipment	85,639,626	76,778
14	(316) Misc. Power Plant Equipment	43,355,229	3,604,662
15	(317) Asset Retirement Costs for Steam Production	1,379,851	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	537,879,632	12,602,216
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	199,508	
38	(341) Structures and Improvements	22,748,227	
39	(342) Fuel Holders, Products, and Accessories	20,975,581	976,399
40	(343) Prime Movers	97,010,314	1,549,161
41	(344) Generators	342,615,279	-3,169,917
42	(345) Accessory Electric Equipment	33,384,957	4,546
43	(346) Misc. Power Plant Equipment	26,620,429	
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	543,554,295	-639,811
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,081,433,927	11,962,405

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	224,057,476	-1,176,931
49	(352) Structures and Improvements	412,470,195	64,442,500
50	(353) Station Equipment	1,265,684,542	148,566,653
51	(354) Towers and Fixtures	895,635,745	-775,330
52	(355) Poles and Fixtures	431,071,958	25,078,087
53	(356) Overhead Conductors and Devices	547,078,033	21,655,047
54	(357) Underground Conduit	335,356,804	19,207,286
55	(358) Underground Conductors and Devices	354,481,023	18,304,890
56	(359) Roads and Trails	310,373,620	-516,288
57	(359.1) Asset Retirement Costs for Transmission Plant	52,868	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	4,776,262,264	294,785,914
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	99,774,974	1,528,947
61	(361) Structures and Improvements	4,156,270	632,301
62	(362) Station Equipment	474,266,942	24,545,646
63	(363) Storage Battery Equipment	37,636,496	626,387
64	(364) Poles, Towers, and Fixtures	638,732,141	41,987,674
65	(365) Overhead Conductors and Devices	553,209,208	65,814,148
66	(366) Underground Conduit	1,106,243,678	77,055,668
67	(367) Underground Conductors and Devices	1,424,296,789	60,691,737
68	(368) Line Transformers	595,325,037	42,468,671
69	(369) Services	468,215,461	22,102,203
70	(370) Meters	248,876,974	1,765,998
71	(371) Installations on Customer Premises	7,987,154	650,626
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	28,014,823	1,727,739
74	(374) Asset Retirement Costs for Distribution Plant	2,080,172	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,688,816,119	341,597,745
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	7,312,143	
87	(390) Structures and Improvements	32,507,793	1,422,218
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	58,146	
90	(393) Stores Equipment	8,546	
91	(394) Tools, Shop and Garage Equipment	24,410,492	1,814,320
92	(395) Laboratory Equipment	5,152,838	-732
93	(396) Power Operated Equipment	60,529	
94	(397) Communication Equipment	247,914,568	23,308,614
95	(398) Miscellaneous Equipment	4,590,487	1,209,098
96	SUBTOTAL (Enter Total of lines 86 thru 95)	322,015,542	27,753,518
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	322,015,542	27,753,518
100	TOTAL (Accounts 101 and 106)	12,012,937,207	687,192,106
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)	12,012,937,207	687,192,106

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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
					2
			222,841		3
1,908,778		87,962	153,458,222		4
1,908,778		87,962	153,681,063		5
					6
					7
			14,526,518		8
			95,472,041		9
			168,150,619		10
					11
			138,276,524		12
			85,716,404		13
			46,959,891		14
	-1,154,935		224,916		15
	-1,154,935		549,326,913		16
					17
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					35
					36
			199,508		37
			22,748,227		38
			21,951,980		39
			98,559,475		40
	6,098,633		345,543,995		41
			33,389,503		42
			26,620,429		43
					44
	6,098,633		549,013,117		45
	4,943,698		1,098,340,030		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
	-832,000		222,048,545		48
399,612		499,589	477,012,672		49
10,405,959		-501,433	1,403,343,803		50
			894,860,415		51
2,329,678	-262,700		453,557,667		52
466,006			568,267,074		53
			354,564,090		54
			372,785,913		55
			309,857,332		56
	1,263,990		1,316,858		57
13,601,255	169,290	-1,844	5,057,614,369		58
					59
68,721	46,188		101,281,388		60
104,150			4,684,421		61
1,068,921			497,743,667		62
			38,262,883		63
9,088,436	-396,423		671,234,956		64
6,058,248	-699,349		612,265,759		65
2,770,395	-1,348,136		1,179,180,815		66
7,457,699	-21,123		1,477,509,704		67
5,576,885			632,216,823		68
1,826,852	-1,785		488,489,027		69
1,477,653			249,165,319		70
20,863			8,616,917		71
					72
105,038			29,637,524		73
	5,969,590		8,049,762		74
35,623,861	3,548,962		5,998,338,965		75
					76
					77
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					79
					80
					81
					82
					83
					84
					85
			7,312,143		86
449,415			33,480,596		87
					88
			58,146		89
			8,546		90
266,570			25,958,242		91
			5,152,106		92
			60,529		93
136,782	-6,272	1,847	271,081,975		94
			5,799,585		95
852,767	-6,272	1,847	348,911,868		96
					97
					98
852,767	-6,272	1,847	348,911,868		99
51,986,661	8,655,678	87,965	12,656,886,295		100
					101
					102
					103
51,986,661	8,655,678	87,965	12,656,886,295		104

Schedule Page: 204 Line No.: 104 Column: g

Reclassification of 2016 Electric Plant-in-Service for Ratemaking
Plant in Service Classified under FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	BOY 2016	EOY 2016
Intangible Plant	144,186,514	153,458,222
Steam Production Plant	550,778,966	564,106,118
Nuclear Production Plant	-	-
Other Production Plant	485,990,944	491,797,479
Transmission Plant	4,715,038,439	4,989,264,259
Distribution Plant	5,777,308,886	6,085,651,791
General Plant	322,015,542	348,911,866
Ratemaking Electric	11,995,319,291	12,633,189,735
ASC 410 (FAS 143 and FIN 47)	3,512,891	9,591,535
Cuyamaca Permanent Adjustment	14,105,025	14,105,025
Total Electric Plant-in-Service	12,012,937,207	12,656,886,295

Total 13-Month Average Plant Balance for 2016 - Steam Production	556,128,077
Total 13-Month Average Plant Balance for 2016 - Nuclear Production	0
Total 13-Month Average Plant Balance for 2016 - Other Production	487,490,103
Total 13-Month Average Plant Balance for 2016 - Transmission Plant	4,857,201,759

* As a result of the SONGS plant closure, the December 2016 Nuclear Production Plant Balance is zero.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Citizens Sunrise Transmission LLC	117 mile-500KV Transmission Line	ER12-	7-02-2042	85,194,000
2		(Border-East Line)	686-000		
3					
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46					
47	TOTAL				85,194,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Salt Creek	7/31/2011	1/31/2017	6,005,098
4				
5	Oceanside	5/31/2012	12/1/2017	360,835
6				
7	Ocean Ranch	3/31/2013	6/18/2018	4,941,795
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
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19				
20				
21	Other Property:			
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46				
47	Total			11,307,728

Schedule Page: 214 Line No.: 46 Column: d

The 13-Month Average Electric Transmission Plant Held for Future Use is $5,653,864.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	SOLAR PHOTOVOLTAIC INITIATIVE	17,915,668
2	TRANSMISSION PROJECTS UNDER $500K	24,223,014
3	TRANSMISSION SUBSTATION PROJECTS UNDER $500K	1,771,904
4	TRANSMISSION LINE EASEMENT RENEWALS	4,121,480
5	CRITICAL ASSET SECURITY	11,858,911
6	TL663 MISSION-KEARNY RECONDUCTOR	6,310,267
7	SUBSTATION SECURITY PROJECTS UNDER $500K	5,635,011
8	IMPERIAL VALLEY SUBSTATION FLOW CONTROLLER	38,140,021
9	SYCAMORE-PENASQUITOS NEW 230KV TIE LINE	65,281,841
10	ARTESIAN 230KV SUBSTATION EXPANSION	2,950,851
11	ORANGE COUNTY LONG RANGE PLAN	45,465,697
12	ELECTRIC TRANSMISSION STREET & HIGHWAY RELOCATIONS	1,049,144
13	SAN LUIS REY SUBSTATION - SYNCHRONOUS CONDENSERS	132,410,223
14	CUYAMACA PEAK ENERGY PLANT	5,590,487
15	MIGUEL SUBSTATION 500KV VOLTAGE SUPPORT	37,399,602
16	SOUTH BAY SUBSTATION RELOCATION	2,038,424
17	TL6926 RINCON-VALLEY CENTER POLE REPLACEMENT	7,218,792
18	SCADA EXPANSION - TRANSMISSION	2,203,785
19	MESA 230KV SUBSTATION	59,195,867
20	CAMP PENDLETON VOLTAGE SUPPORT	2,000,680
21	AUTOMATED FAULT DETECTION INSTALLATIONS	1,055,431
22	TL628 CABLE REPLACEMENT	3,620,228
23	LOS COCHES SUBSTATION REBUILD	5,121,532
24	TL674A RECONFIGURE	1,414,251
25	TL649 POLE REPLACEMENT	3,515,064
26	SYNCHRONIZED PHASOR MEASUREMENT SYSTEM	1,287,722
27	TL615/659 CABLE REPLACEMENT	2,429,593
28	TL633 RECONDUCTOR	4,778,607
29	CONDITION BASED MONITORING - CIRCUIT BREAKERS	4,147,796
30	MERCHANT SWITCHYARD	15,398,754
31	MIGUEL SUBSTATION SITE IMPROVEMENTS	3,409,709
32	FIBER OPTIC FOR RELAY PROTECTION & TELECOMMUNICATION	9,345,816
33	SUBSTATION MONITORING EQUIPMENT - TRANSMISSION	1,569,123
34	TRANSMISSION INFRASTRUCTURE IMPROVEMENTS	19,651,442
35	TL695 SW POLE REPLACEMENT	2,664,589
36	TL676 MISSION - MESA HEIGHTS RECONDUCTOR	3,201,915
37	WARNER SUBSTATION 69KV RELAY UPGRADES	1,155,271
38	AERIAL MARKING FOR SAFETY	2,436,298
39	MISSION SUBSTATION BANK ADDITION	2,096,139
40	CLEVELAND NATIONAL FOREST POLE REPLACEMENTS	114,611,073
41	TL13821 & TL13828 JUNCTION ENHANCEMENT	13,160,337
42	138KV & 69KV CIRCUIT BREAKER UPGRADES	1,939,083
43	TOTAL	989,342,926

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	TRANSMISSION SYSTEM AUTOMATION	4,011,901
2	DISTRIBUTION SUBSTATION RELIABILITY	2,896,438
3	CONVERSION FROM OH TO UG RULE 20A	12,606,739
4	CITY OF SAN DIEGO SURCHARGE PROGRAM	3,146,889
5	UG RESIDENTIAL NEW BUSINESS	3,111,436
6	TL664 WOOD POLE REPLACEMENT	2,158,663
7	SUBSTATION AUXILIARY POWER SYSTEMS	1,154,354
8	OH DISTRIBUTION SERVICE MANAGEMENT	2,843,341
9	CORRECTIVE MAINTENANCE PROGRAM	2,979,590
10	REPLACEMENT OF UNDERGROUND CABLES	3,161,572
11	WOOD POLE REINFORCEMENT	7,088,658
12	LOAD INTEGRATION CAPACITY ANALYSIS	1,647,313
13	KEARNY SUBSTATION REBUILD	4,825,374
14	KETTNER SUBSTATION REBUILD	12,304,601
15	BORREGO SPRINGS MICROGRID ENHANCEMENTS	6,138,327
16	DISTRIBUTION SUBSTATION SCADA EXPANSION	3,063,947
17	NEW 12KV CIRCUIT C1448	1,079,377
18	FIRE HAZARD PREVENTION	3,394,861
19	DISTRIBUTION SYSTEM CAPACITY IMPROVEMENT	1,844,996
20	EXPEDITED STORAGE PROCUREMENT	55,925,746
21	OCEAN RANCH LAND PURCHASE	2,628,918
22	SUBSTATION CAPACITOR BANK UPGRADES	3,378,721
23	EMERGENCY TRANSFORMERS & SWITCHGEAR	6,270,406
24	JAMUL SUBSTATION	1,230,597
25	SALT CREEK SUBSTATION	26,035,491
26	MID-COAST TROLLEY EXTENSION PROJECT	6,944,079
27	SEWAGE PUMP STATION REBUILDS	7,769,949
28	VANDIUM FLOW BATTERY PROJECT	4,758,013
29	FIRE THREAT ZONE PROTECTION & SCADA UPGRADE	2,234,639
30	CONDITION BASED MONITORING - SMART GRID	1,959,633
31	DISTRIBUTION CIRCUIT RELIABILITY CONSTRUCTION	1,784,588
32	STRATEGIC FIRE HARDENING	30,263,968
33	12KV CIRCUIT EXTENSION C100	1,245,870
34	MASTER METER MOBILE HOME PARK TRANSFERS	13,363,108
35	OBSOLETE SUBSTATION EQUIPMENT REPLACEMENT	2,339,394
36	CORRECTIVE MAINT. PROG. (CMP) UG SWITCH REPLAC. & MANHOLE REPAIR	2,573,655
37	SMART GRID ANOMALY DETECTION	11,987,046
38	VEHICLE GRID TECHNOLOGY INTEGRATION	1,502,951
39	MISSION CONTROL SECURITY HARDENING	5,497,652
40	TL6975 ESCONDIDO - SAN MARCOS	1,729,192
41	TL690 WOOD TO STEEL REPLACEMENT	1,112,917
42	POWAY SUBSTATION REBUILD	8,379,756
43	TOTAL	989,342,926

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	TL691 WOOD TO STEEL REPLACEMENT	1,482,852
2	ELECTRIC DISTRIBUTION STREET & HIGHWAY RELOCATIONS	1,754,425
3	UNALLOCATED CONSTRUCTION OVERHEADS & LABOR ACCRUAL	-5,163,083
4	MINOR PROJECTS (LESS THAN $1,000,000)	20,102,624
5	RESEARCH, DEVELOPMENT & DEMONSTRATION	
6		
7		
8	ANNUAL CHANGES IN PROJECT BALANCES ARE DUE TO COMPLETION OF	
9	SEPARATE SEGMENTS OF THE BUDGET.	
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38		
39		
40		
41		
42		
43	TOTAL	989,342,926

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	3,859,555,061	3,848,087,212		11,467,849
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	400,462,393	400,462,393		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others	2,793,195			2,793,195
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	403,255,588	400,462,393		2,793,195
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	50,009,162	50,009,162		
13	Cost of Removal	59,301,047	59,301,047		
14	Salvage (Credit)	1,886,682	1,886,682		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	107,423,527	107,423,527		
16	Other Debit or Cr. Items (Describe, details in footnote):	-36,789,581	-36,789,581		
17					
18	Book Cost or Asset Retirement Costs Retired	28,526,009	28,526,009		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,147,123,550	4,132,862,506		14,261,044
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	216,559,576	216,559,576		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	206,907,399	206,907,399		
25	Transmission	970,329,303	956,068,259		14,261,044
26	Distribution	2,615,090,125	2,615,090,125		
27	Regional Transmission and Market Operation				
28	General	138,237,147	138,237,147		
29	TOTAL (Enter Total of lines 20 thru 28)	4,147,123,550	4,132,862,506		14,261,044

Schedule Page: 219 Line No.: 3 Column: c

Depreciation Provision - Electric Only (Line 10, Page 219)	$ 400,462,393
Depreciation Provision - Common Alloc. to Elec. (Line 10, pg 336)	26,344,847
Depreciation Provision - (Line 6, Col. G, Page 115)	$ 426,807,240

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

Book Cost of Plant Retired (Line 12, Col. B, Page 219)	$(50,009,162)
Total Plant Retired (Line 95, Col. D, Page 207	51,986,661
Adj. For Land & Intangible Retirements not impacting A/C 108	(1,977,499)
Adj. For Net Book Value of Plant Retired to Gain on Sale	0
Difference:	$ 0

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

SONGS Decommissioning - Current Year Trust Income (Loss)	$(36,846,491)
Transfer of Reserve Balances between Departments	56,911
Other Debit and Credit Items (Line 16, Page 219)	$(36,789,581)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)
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42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	5,493,301	2,289,968	
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)	6,104,647	8,893,053	ELECTRIC/GAS
6	Assigned to - Operations and Maintenance	7,048,895	7,603,749	ELECTRIC/GAS
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	91,429,468	96,318,462	ELECTRIC/GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	104,583,010	112,815,264	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			COMMON
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			COMMON
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	110,076,311	115,105,232	

Schedule Page: 227 Line No.: 12 Column: c

Reclassification of FERC Form 1 2016 Materials & Supplies, Page 227, for Ratemaking

Materials and Supplies
Classified
In accordance with Guidelines in
FERC Order 888

	BOY 2016	EOY 2016	
Total Materials and Supplies (FERC 154)	104,583,010	112,815,264	1
As Assigned to Department for Ratemaking			
Electric Department	101,319,984	109,544,804	
Gas Department	3,263,026	3,270,460	
Less Line 5 (Construction Estimate)			
Electric Department	(5,787,452)	(8,562,720)	
Gas Department	(317,195)	(330,333)	
Total Allowable Materials and Supplies			
Electric Department	95,532,532	100,982,084	
Gas Department	2,945,831	2,940,126	
Total Allowable Materials and Supplies per FERC Formula	98,478,363	103,922,211	2
Total 13-Month Average Electric M&S for 2016	91,724,081	97,383,389	

[1] Ties to Line 12 of FERC Form 1, pages 227

[2] Ties to Line 12 minus Line 5 of FERC Form 1, pages 227

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		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	79,929.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	12,947.00		12,947.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Transfer to Palomar	-5.00			
10	Transfer to Miramar				
11	Transfer to Desert Star	-3.00			
12					
13					
14					
15	Total	-8.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	92,868.00		12,947.00	
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
San Diego Gas & Electric 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		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						79,929.00		1
								2
								3
12,947.00		12,947.00		349,569.00		401,357.00		4
								5
								6
								7
								8
						-5.00		9
								10
						-3.00		11
								12
								13
								14
						-8.00		15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
12,947.00		12,947.00		349,569.00		481,278.00		29
								30
								31
								32
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
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
San Diego Gas & Electric 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		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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						
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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
San Diego Gas & Electric 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	SONGS Plant Shutdown Project	257,519,437		Various	74,772,292	182,747,145
22	Electric Legacy Meters Project	32,187,988		Various	16,067,238	16,120,750
23	Sycamore-Bernardo Project	1,366,481				1,366,481
24						
25						
26						
27						
28						
29						
30						
31						
32						
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35						
36						
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46						
47						
48						
49	TOTAL	291,073,906			90,839,530	200,234,376

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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20					
21	**Generation Studies**				
22					
23					
24					
25					
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39					
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Name of Respondent San Diego Gas & Electric 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

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Taxes Recoverable in Rates	946,975,066	93,805,084	Various		1,040,780,150
2	Amortized Over Various Lives					
3						
4	Post Retirement Benefits Other Than Pension	4,394,249	16,841,942			21,236,191
5						
6	Workers Compensation (IBNR)		229,976	186 / 228	229,976	
7						
8	Employer's Accounting for Postemplyment Benefits	5,518,000		228/232/14	1,841,000	3,677,000
9						
10	Environmental Clean-Up	1,953,398	203,958	242 / 253	537,972	1,619,384
11						
12	Balancing Account Undercollections	1,060,841,939		456 / 495	500,965,629	559,876,310
13						
14	Pension Benefits	175,902,776	12,375,408			188,278,184
15						
16	SONGS Mitigation	13,820,507	32,628,032			46,448,539
17						
18	Electric Derivatives	175,718,168	80,637,594	175 / 244	13,307,153	243,048,609
19						
20	Contribution to City of Escondido	1,597,814		253	124,798	1,473,016
21	(20 year life, starting 2006)					
22						
23	Asset Retirement Obligations	20,735,191	1,117,485	230	6,973,925	14,878,751
24						
25	2007 Excess Wildfire Claims	363,378,946	912,167	456	10,527,582	353,763,531
26						
27	Sunrise Wildfire Mitigation	117,049,132	956,461			118,005,593
28						
29	Beyond The Meter	197,997	8,266,219	232	381,765	8,082,451
30						
31	Unamortized Line of Credit (LOC) Net		1,437,985			1,437,985
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	2,888,083,183	249,412,311		534,889,800	2,602,605,694

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Debt Issuance Costs	875,661	738,388	181	990,078	623,971
2						
3	Southwest Powerlink Deferred					
4	per CPUC					
5	(amortization 1/1986 - 12/2023)	363,754		406	15,744	348,010
6						
7	Mitigation Fund	150,328				150,328
8						
9	Campo Wind Farm Project	305,580		101	305,580	
10						
11	Invenergy Cost Sharing	729,406		101	729,406	
12						
13	Long-Term Purch Power Rcvble	12,495,975		232	12,495,975	
14						
15	Invenergy Wind Development	238,525		101	238,525	
16						
17	Environmental Program	7,185,310		various	15,277	7,170,033
18						
19	Oracle Costs	1,046,846				1,046,846
20						
21	Workers Comp Receivable	8,155,675	2,605,048	various	2,716,462	8,044,261
22						
23	SONGS Decommissioning	2,196,593	2,882,081	228	3,274,886	1,803,788
24						
25	Pendleton Energy Park	195,734				195,734
26						
27	Gaskell Tax Equity	203,274		184	87,962	115,312
28						
29	Supervisory Control & Data	739,982		various	225,248	514,734
30	Acquisition Equipment					
31						
32	Fenton Land Rights	157,984		various	157,984	
33						
34	Miscellaneous Other	159,236	66,224	593, 921	86,753	138,707
35						
36	Misc. Deferred Debits - SONGS		3,442,787	232,120	204,558	3,238,229
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	35,199,863				23,389,953

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Federal	167,867,763	125,517,335
3	State	76,611,001	69,353,253
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	244,478,764	194,870,588
9	Gas		
10	Federal	15,849,819	34,664,148
11	State	3,486,769	3,539,965
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	19,336,588	38,204,113
17	Other (Specify) Non-Utiltity	12,232,420	83,877,846
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	276,047,772	316,952,547

Notes

Schedule Page: 234 Line No.: 2 Column: b

Electric balance in Account 190 at the end of the year reflects a reduction for amortization of transmission related excess deferred federal income taxes in the amount of $0.

Schedule Page: 234 Line No.: 2 Column: c

Electric balance in Account 190 at the end of the year reflects a reduction for amortization of transmission related excess deferred federal income taxes in the amount of $0.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common	255,000,000	2.50	
2				
3	Preferred Stock	45,000,000		
4				
5				
6				
7	Note: All the Common Stock of San Diego Gas &			
8	Electric is owned by Enova Corporation and is			
9	not publicly traded.			
10				
11				
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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)	
116,583,358	291,458,395					1
						2
						3
						4
						5
						6
						7
						8
						9
						10
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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 - None	
2		
3	ACCOUNT 209 - None	
4		
5	ACCOUNT 210 - None	
6		
7	ACCOUNT 211	
8	Asset Transferred from Sempra Energy	79,665,369
9	Equity infusion from Enova Corporation	400,000,000
10	Total Account 211	479,665,369
11		
12		
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40	TOTAL	479,665,369

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	24,605,640
2		
3		
4		
5		
6		
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8		
9		
10		
11		
12		
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14		
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16		
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21		
22	TOTAL	24,605,640

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	ACCOUNT 221 - BONDS		
2			
3	FIRST MORTGAGE BONDS		
4	5.875% Series VV due 2034	43,615,000	1,509,414
5			
6	5.875% Series WW due 2034	40,000,000	1,385,317
7			
8	5.875% Series XX due 2034	35,000,000	1,213,328
9			
10	5.875% Series YY due 2034	24,000,000	832,448
11			
12	5.875% Series ZZ due 2034	33,650,000	1,165,922
13			
14	4.000% Series AAA due 2039	75,000,000	3,089,247
15			
16	5.350% Series BBB due 2035	250,000,000	2,709,950
17			295,000 D
18	6.000% Series DDD due 2026	250,000,000	2,429,000
19			1,117,500 D
20	1.650% Series EEE due 2018	161,240,000	4,375,665
21			
22	6.125% Series FFF due 2037	250,000,000	2,556,327
23			780,000 D
24	6.000% Series GGG due 2039	300,000,000	3,057,571
25			1,380,000 D
26	5.350% Series HHH due 2040	250,000,000	2,486,955
27			335,000 D
28	4.500% Series III due 2040	500,000,000	5,044,008
29			5,515,000 D
30	3.000% Series JJJ due 2021	350,000,000	2,775,568
31			1,795,500 D
32	3.950% Series LLL due 2041	250,000,000	2,639,787
33	TOTAL	4,706,155,000	66,150,070

Name of Respondent San Diego Gas & Electric 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

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			350,000 D
2	4.300% Series MMM due 2042	250,000,000	2,569,738
3			1,297,500 D
4	3.600% Series NNN due 2023	450,000,000	3,670,004
5			72,000 D
6	1.151% Series OOO due 2017	140,000,000	439,916
7			
8	1.914% Series PPP due 2022	250,000,000	1,715,986
9			
10	2.500% Series QQQ due 2026	500,000,000	4,279,086
11			1,625,000 D
12	5.000% Series OO due 2027	250,000,000	1,615,079
13			
14	TOTAL ACCOUNT 221	4,652,505,000	66,122,816
15			
16	ACCOUNT 222-REACQUIRED BONDS-NONE		
17			
18	ACCOUNT 223-ADVANCES FROM ASSOCIATED COMPANIES-NONE		
19			
20	ACCOUNT 224-OTHER LONG TERM DEBT		
21			
22	Long Term Commercial Paper, 1.05%	53,650,000	27,254
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	4,706,155,000	66,150,070

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
06/17/04	02/15/34	06/17/04	02/15/34	43,615,000	2,562,381	4
						5
06/17/04	02/15/34	06/17/04	02/15/34	40,000,000	2,350,000	6
						7
06/17/04	02/15/34	06/17/04	02/15/34	35,000,000	2,056,250	8
						9
06/17/04	01/01/34	06/17/04	01/01/34	24,000,000	1,410,000	10
						11
06/17/04	01/01/34	06/17/04	01/01/34	33,650,000	1,976,937	12
						13
06/17/04	05/01/39	06/17/04	05/01/39	75,000,000	3,000,000	14
						15
05/19/05	05/15/35	05/19/05	05/15/35	250,000,000	13,375,000	16
						17
06/08/06	06/01/26	06/08/06	06/01/26	250,000,000	15,000,000	18
						19
09/21/06	07/01/18	09/21/06	07/01/18	161,240,000	2,660,460	20
						21
09/20/07	09/15/37	09/20/07	09/15/37	250,000,000	15,312,500	22
						23
05/14/09	06/01/39	05/14/09	06/01/39	300,000,000	18,000,000	24
						25
05/13/10	05/15/40	05/13/10	05/15/40	250,000,000	13,375,000	26
						27
08/26/10	08/15/40	08/26/10	08/15/40	500,000,000	22,500,000	28
						29
08/18/11	08/15/21	08/18/11	08/15/21	350,000,000	10,500,000	30
						31
11/17/11	11/15/41	11/17/11	11/15/41	250,000,000	9,875,000	32
				4,348,934,000	176,236,940	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
03/22/12	04/01/42	03/22/12	04/01/42	250,000,000	10,750,000	2
						3
09/09/13	09/01/23	09/09/13	09/01/23	450,000,000	16,200,000	4
						5
03/12/15	03/09/17	03/12/15	03/09/17	140,000,000	1,203,317	6
						7
03/12/15	02/01/22	03/12/15	02/01/22	196,429,000	3,930,543	8
						9
05/19/16	05/15/26	05/19/16	05/15/26	500,000,000	7,728,495	10
						11
12/01/92	12/01/27	12/01/92	12/01/27		1,962,500	12
						13
				4,348,934,000	175,728,383	14
						15
						16
						17
						18
						19
						20
						21
11/19/15	11/21/16	11/19/15	11/21/16		508,557	22
						23
						24
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						31
						32
				4,348,934,000	176,236,940	33

Schedule Page: 256.1 Line No.: 14 Column: c

Expense	$51,560,316
Discount	$14,562,500
Account 221	$66,122,816

Schedule Page: 256.1 Line No.: 32 Column: a

Item 2:

FERC authorization is not required on routine issues.

Item 11:

In May 2016:
1) 5.000% bond series OO2 for $60,000,000 and OO4 for $45,000,000 were called at a loss.
2) SDGE issued 2.500% First Mortgage bond series QQQ for $500,000,000 due 2026.

In November 2016 1.050% long term commercial paper for $53,650,000 matured.

Item 15:

Account 221	$175,728,383
Account 224	$ 508,557
	$176,236,940

Item 16:

D.15-08-011 - In August 2015, SDG&E received authority from the California Public Utilities Commission to issue $1,000,000,000 of new debt under Decision 15-08-011 and $300,000,000 in rollover debt. In May 2016 SDG&E issued 2.500% First Mortgage bond series QQQ for $500,000,000 due 2026. At December 2016 total remaining authority for new debt was $670,430,000 and rollover debt was $300,000,000.

Schedule Page: 256.1 Line No.: 32 Column: c

Expense	$27,254
Discount	$ 0
	$27,254

FOOTNOTE DATA

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2016/Q4

FOOTNOTE DATA

[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	569,569,312
2		
3		
4	Taxable Income Not Reported on Books	
5	Regulatory Balancing Accounts	91,799,780
6	Contributions in Aid of Construction	39,262,709
7	SONGS Decommissioning Costs	36,336,244
8	Other (Itemized within footnote)	9,982,496
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation on Fixed Assets	567,384,545
11	Federal and State Taxes	279,516,924
12	Amortization and Interest Capitalized	51,770,528
13	Other (Itemized within footnote)	-1,795,728
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	-61,585,145
16	Deferred Construction Revenue	-7,319,637
17	Keyman Life Insurance	-5,578,007
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation on Fixed Assets	-748,177,144
21	481a - Wildfire Settlements	-414,922,142
22	Percentage Repair Allowance	-110,519,392
23	Current State Tax Deduction	-92,647,119
24	Software Development Costs	-71,913,609
25	Removal Costs	-61,497,571
26	Other (Itemized within footnote)	44,581,305
27	Federal Tax Net Income	24,778,991
28	Show Computation of Tax:	
29	Federal Tax @ 35%	8,672,647
30	Deferred Taxes	211,348,453
31	Tax Credits and Other Ajustments (net)	-1,690,551
32	Fed Discete Taxes	1,060,382
33	Total Federal Income Tax Expense	219,390,931
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 8 Column: b

Fuel Tax Credit Addback	$ 8,000
GAA Retirements Election	9,974,496
Total	$ 9,982,496

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

SERP	387,413
Miscellaneous Expenses	(2,183,141)
Total	$ (1,795,728)

Schedule Page: 261 Line No.: 17 Column: b

South Georgia Adjustment of $2,333,000 is included in book taxable income to reverse tax benefits flowed through in rates prior to full normalization of book/tax adjustments.

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

Amortization of Loss on Reacquired Debt	$ (2,644,717)
Contingency Book Reserves	(2,936,855)
Abandonment Loss	(4,688,653)
Miscellaneous Expenses	(1,084,397)
Property Tax/Ad Valorem	(900,626)
Restricted Stock Awards	(17,922,997)
Facts & Circumstances Repairs	(14,403,060)
Total	$(44,581,305)

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)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	LOCAL:					
2	Ad Valorem (Note 1)		860,997	111,830,321	122,159,208	-10,351,467
3	Sales and Use	18,241		252,324	191,772	
4	Business License			59,899	59,899	
5						
6	SUBTOTAL	18,241	860,997	112,142,544	122,410,879	-10,351,467
7						
8	STATE:					
9	Franchise (Note 3)		2,577,393	22,233,507	54,312,581	5,870,102
10	Unemployment (Note 4)	346,168		1,312,974	1,062,721	
11	Sales and Use (Note 2)	61,036		756,974	575,314	
12	Fuel Tax	8,494		6,926	13,717	
13						
14	SUBTOTAL	415,698	2,577,393	24,310,381	55,964,333	5,870,102
15						
16	FEDERAL:					
17	Taxes on Income (Note 3)		3,831,535		82,600,000	
18	Retirement (Note 4)	863,957		27,543,700	27,369,417	
19	Unemployment (Note 4)	551,987		340,132	200,004	
20	Medicare (Note 4)	213,049		8,141,934	8,112,168	-40
21	Fuel Tax	-33,457		-163,809	-229,101	
22						
23						
24	SUBTOTAL	1,595,536	3,831,535	35,861,957	118,052,488	-40
25						
26	Other - Foreign Tax					
27						
28						
29						
30						
31	Note 1					
32						
33	Note 2					
34						
35	Note 3					
36						
37	Note 4					
38						
39						
40						
41	TOTAL	2,029,475	7,269,925	172,314,882	296,427,700	-4,481,405

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
	838,416	100,320,026			11,510,295	2
78,793					252,324	3
		54,851			5,048	4
						5
78,793	838,416	100,374,877			11,767,667	6
						7
						8
	40,526,569	16,395,774			5,837,733	9
596,420		998,504			314,470	10
242,696					756,975	11
1,703					6,926	12
						13
840,819	40,526,569	17,394,278			6,916,104	14
						15
						16
	86,431,535					17
1,038,240		9,857,691			17,686,009	18
692,115		258,667			81,465	19
242,774		2,913,940			5,227,993	20
31,835					-163,809	21
						22
						23
2,004,964	86,431,535	13,030,298			22,831,658	24
						25
						26
						27
						28
						29
						30
						31
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						39
						40
2,924,576	127,796,520	130,799,453			41,515,429	41

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

This adjustment is for a portion of property taxes paid on construction work in process. The property tax charged during the year was reduced and capitalized to certain assets under construction.

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

Amount includes Ad Valorem taxes on SONGS in the amount of $2,707,851

Property Tax expense of $604,652 associated with the Citizens portion of the Border-Eastline are deducted and moved to column (l).

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

Includes property tax expense of $604,652 associated with the Citizens portion of the Border-Eastline.

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

Description	Adjustment Amount	FERC 165/236	FERC 146000C
Balance Sheet Reclassification Between Federal and State	-	-	-
Balance Sheet Reclassification Due to FIN 48 Liabilities	944,057	(944,057)	-
Adoption of ASU 2016-098 Stock Comp	4,926,045	-	(4,926,045)
Total - California Corporation Franchise Tax Adjustment	5,870,102	(944,057)	(4,926,045)

Schedule Page: 262 Line No.: 18 Column: i

Payroll Tax expense of $29,834 associated with the Citizens portion of the Border-Eastline are deducted and moved to column (l).

Schedule Page: 262 Line No.: 18 Column: l

Includes property tax expense of $29,834 associated with the Citizens portion of the Border-Eastline.

Schedule Page: 262 Line No.: 31 Column: a

Note 1:
Ad Valorem taxes are allocated based on type of assets in each taxing jurisdiction.

Schedule Page: 262 Line No.: 33 Column: a

Note 2:
Sales and Use taxes are allocated based on the Common Allocation Factor.

Schedule Page: 262 Line No.: 35 Column: a

Note 3:
State and Franchise Tax and Federal Income Tax are charged to departments based on total taxable income generated by each department.

Schedule Page: 262 Line No.: 37 Column: a

Note 4:
Retirement, Unemployment, and Medicare taxes are charged to departments as a percentage of total taxable labor charged.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Various	15,715,643			411.4	2,180,730	
7							
8	TOTAL	15,715,643				2,180,730	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility Various	3,013,288			411.4	512,929	
11							
12							
13							
14							
15							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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
			3
			4
			5
13,534,913	25 to 30 years		6
			7
13,534,913			8
			9
2,500,359	25 to 30 years		10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			47
			48

Schedule Page: 266 Line No.: 8 Column: f

Transmission related amortization of investment tax credits allocated to current year income is $264,763.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	CIAC/CAC Tax Gross-Ups	70,035,128	456/495	14,806,735	12,967,270	68,195,663
2	Amortized over various 31 yr lives					
3						
4	SONGS Mitigation	12,834,459	182.3	739,925	33,387,841	45,482,375
5						
6	OII Insurance Limited	3,704,500	924	599,500	2,998,000	6,103,000
7						
8	Sunrise Fire Mitigation Liability	113,747,394	182.3	3,367,771	4,258,197	114,637,820
9						
10	CA ISO Fund Due to Customers	12,495,975	186	12,495,975		
11						
12	Citizens Lease	72,538,668	242	2,836,960		69,701,708
13						
14	GHG Allowance	33,736,971	158	65,463,439	103,644,206	71,917,738
15						
16	Miscellaneous	14,069,586	Various	58,430,386	57,757,570	13,396,770
17						
18						
19						
20						
21						
22						
23						
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41						
42						
43						
44						
45						
46						
47	TOTAL	333,162,681		158,740,691	215,013,084	389,435,074

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
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)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							21

NOTES (Continued)

Name of Respondent San Diego Gas & Electric 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

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	1,917,894,570	180,891,924	131,690,593
3	Gas	135,725,221	47,399,425	5,723,552
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,053,619,791	228,291,349	137,414,145
6				
7	Non Utility	-21,989,568		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,031,630,223	228,291,349	137,414,145
10	Classification of TOTAL			
11	Federal Income Tax	1,823,560,878	211,173,916	121,651,101
12	State Income Tax	208,069,345	17,117,433	15,763,044
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
				182.3	24,094,532	1,991,190,433	2
				182.3	1,450,537	178,851,631	3
							4
					25,545,069	2,170,042,064	5
							6
75,325,141	5,316,058			182.3	18,927,594	66,947,109	7
							8
75,325,141	5,316,058				44,472,663	2,236,989,173	9
							10
60,136,403	5,316,058				32,280,210	2,000,184,248	11
15,188,738					12,192,453	236,804,925	12
							13

NOTES (Continued)

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

Non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $878,415,167.

Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $23,707,268.

Allocated General and Common accumulated deferred federal income taxes included in transmission related accumulated deferred federal income taxes at the beginning of the year was $17,331,399.

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

Non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $931,658,150.

Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $22,885,191.

Allocated General and Common accumulated deferred federal income taxes included in transmission related accumulated deferred income taxes at the end of the year was $18,824,308.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		602,792,144	308,815,177	146,683,257
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	602,792,144	308,815,177	146,683,257
10	Gas			
11		60,769,819	6,487,329	8,672,364
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	60,769,819	6,487,329	8,672,364
18	Non Utility	25,826,587		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	689,388,550	315,302,506	155,355,621
20	Classification of TOTAL			
21	Federal Income Tax	540,149,115	253,627,830	128,382,030
22	State Income Tax	149,239,435	61,674,676	26,973,591
23	Local Income Tax			

NOTES

Name of Respondent San Diego Gas & Electric 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

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
		282	4,313,684	Various	12,775,640	773,386,020	3
							4
							5
							6
							7
							8
			4,313,684		12,775,640	773,386,020	9
							10
				Various	1,278,098	59,862,882	11
							12
							13
							14
							15
							16
					1,278,098	59,862,882	17
1,248,164	1,338,922			182.3	13,023,790	38,759,619	18
1,248,164	1,338,922		4,313,684		27,077,528	872,008,521	19
							20
1,014,371	1,085,439		3,724,341		21,202,955	682,802,461	21
233,793	253,483		589,343		5,874,573	189,206,060	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 9 Column: b

Transmission allocation of accumulated deferred income taxes related to electric miscellaneous intangible plant at the beginning of the year was $5,628,143.

Schedule Page: 276 Line No.: 9 Column: k

Transmission allocation of accumulated deferred income taxes related to electric miscellaneous intangible plant at the end of the year was $7,442,748.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Deferred Taxes Payable in rates	32,560,521	190, 282 / 283	6,258,983		26,301,538
3						
4						
5	Asset Retirement Obligations	500,909,066	230	137,500,004	152,593,162	516,002,224
6						
7						
8	Balancing Account Overcollections	756,390,142	456	437,199,653		319,190,489
9						
10						
11	Electric / Gas Derivatives	76,329,229	175.1		25,770,494	102,099,723
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	1,366,188,958		580,958,640	178,363,656	963,593,974

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	1,385,389,551	1,486,308,656
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,312,141,086	1,507,963,745
5	Large (or Ind.) (See Instr. 4)	355,650,412	380,735,134
6	(444) Public Street and Highway Lighting	13,575,324	15,263,946
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,066,756,373	3,390,271,481
11	(447) Sales for Resale	430,362,414	579,635,264
12	TOTAL Sales of Electricity	3,497,118,787	3,969,906,745
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	3,497,118,787	3,969,906,745
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	85,186,823	93,141,013
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	6,563,517	4,311,346
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	328,495,290	-54,553,380
22	(456.1) Revenues from Transmission of Electricity of Others	258,199,601	291,649,708
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	678,445,231	334,548,687
27	TOTAL Electric Operating Revenues	4,175,564,018	4,304,455,432

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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
6,684,887	7,143,500	1,272,052	1,264,642	2
				3
6,700,346	6,877,018	150,591	149,517	4
2,193,185	2,163,463	461	464	5
74,621	83,032	2,028	2,037	6
				7
				8
				9
15,653,039	16,267,013	1,425,132	1,416,660	10
13,790,851	16,865,020			11
29,443,890	33,132,033	1,425,132	1,416,660	12
				13
29,443,890	33,132,033	1,425,132	1,416,660	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

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

Description

San Diego Franchise Fee Surcharge	$80,045,984
Service Establishment	3,567,317
Late Payment Charge	597,838
Other*	975,684
	$85,186,823

* Individual balances are less than $250,000

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

Description

San Diego Franchise Fee Surcharge	$88,007,838
Service Establishment	2,427,250
Late Payment Charge	721,575
Other*	1,984,350
	$93,141,013

* Individual balances are less than $250,000

Schedule Page: 300 Line No.: 19 Column: b

Includes Transmission Revenue Credits of $1,732,846

Schedule Page: 300 Line No.: 19 Column: c

Includes Transmission Revenue Credits of $709,930

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

Description

Direct Access	$223,238,550
Balancing Accounts	(7,186,248)
Cap and Trade Revenues	82,024,128
Litigation	3,678,316
CIAC Income Tax	6,391,174
Shared Assets	4,870,607
PUC Reimbursement Fee	6,184,516
Government Turnkey	717,068
Unbilled Revenue	1,896,000
Joint Pole Activity	1,862,654
Generation Trans. Interconnection Rev.	2,270,401
Affiliation Empl Transfer Fees	317,745
Other*	2,230,379
	$328,495,290

* Individual balances are less than $250,000
* Inclul des Transmission Revenue Credits of $3,330,372

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

Description

Direct Access	$229,490,396
Balancing Accounts	(406,521,543)
Cap and Trade Revenues	79,929,224
Litigation	11,536,390
CIAC Income Tax	6,033,360
Shared Assets	6,795,152
PUC Reimbursement Fee	4,565,807
Government Turnkey	595,187
Unbilled Revenue	1,246,000
Joint Pole Activity	1,429,367
Generation Trans. Interconnection Rev.	4,002,531
Electric Revenue Cycle Credits	6,104,749
Other*	240,000
	($54,553,380)

* Individual balances are less than $250,000
* Includes Transmission Revenue Credits of $5,861,554

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

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	DR	5,177,073	1,183,152,035	995,273	5,202	0.2285
2	DRTOU	75,354	13,888,871	13,607	5,538	0.1843
3	EVTOU	87,238	17,467,464	7,776	11,219	0.2002
4	DRLI	1,130,759	138,751,692	249,158	4,538	0.1227
5	DM	44,653	9,679,685	3,610	12,369	0.2168
6	DS	17,687	2,383,493	234	75,585	0.1348
7	DT	150,262	19,382,690	438	343,064	0.1290
8	OL-1	1,630	548,164	1,912	853	0.3363
9	DWL	231	135,457	44	5,250	0.5864
10	Total Residential Sales (440)	6,684,887	1,385,389,551	1,272,052	5,255	0.2072
11						
12	A	385,968	73,163,063	21,791	17,712	0.1896
13	ATOU	12,744	2,604,340	231	55,169	0.2044
14	ASTOD	1,660,101	345,058,701	105,678	15,709	0.2079
15	AD	30,488	6,912,544	174	175,218	0.2267
16	UM	6,258	1,355,406	75	83,440	0.2166
17	PA	20,454	3,285,951	858	23,839	0.1607
18	PAT1	284,283	44,794,238	3,017	94,227	0.1576
19	AL-TOU	4,198,012	811,418,856	16,600	252,892	0.1933
20	SPSS	40	-3,560	5	8,000	-0.0890
21	DG		113,008			
22	AY-TOU	93,736	21,434,207	382	245,382	0.2287
23	OL-1	4,605	1,248,588	1,739	2,648	0.2711
24	OLTOU	3,657	755,744	41	89,195	0.2067
25	Total Commerical (444)	6,700,346	1,312,141,086	150,591	44,494	0.1958
26						
27	AL-TOU	2,153,001	346,949,228	447	4,816,557	0.1611
28	DG		419,630			
29	A6-TOU	40,184	8,281,554	14	2,870,286	0.2061
30	Total Industrial (442)	2,193,185	355,650,412	461	4,757,451	0.1622
31						
32	LS1	14,905	5,456,722	771	19,332	0.3661
33	LS2	57,943	7,866,893	1,104	52,485	0.1358
34	LS3	1,773	251,709	153	11,588	0.1420
35	Total Public Street and Hwy (444)	74,621	13,575,324	2,028	36,795	0.1819
36						
37						
38						
39						
40						
41	TOTAL Billed	15,653,039	3,066,756,373	1,425,132	10,984	0.1959
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	15,653,039	3,066,756,373	1,425,132	10,984	0.1959

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Arizona Public Service Company	SF	FERC Vol. 10			
2	California ISO					
3	City of Escondido (Rincon Hydro Plant)	SF	FERC Vol. 10			
4	City of Anaheim	SF	FERC Vol. 10			
5	City of Burbank	SF	FERC Vol. 10			
6	Citigroup Energy LLC	SF	FERC Vol. 10			
7	EDF Trading North America LLC	SF	FERC Vol. 10			
8	Energy America LLC	SF	FERC Vol. 10			
9	Exelon Generation Company LLC	SF	FERC Vol. 10			
10	Los Angeles Dept. of Water & Power	SF	FERC Vol. 10			
11	Morgan Stanley Capital Group	SF	FERC Vol. 10			
12	Pilot Power Group Inc	SF	FERC Vol. 10			
13	Powerex Corporation	SF	FERC Vol. 10			
14	Shell Energy North America (US) LP	SF	FERC Vol. 10			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	Southern California Edison	SF	FERC Vol. 10			
2	TransAlta Energy Marketing US	SF	FERC Vol. 10			
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
470		23,266		23,266	1
13,375,596		415,148,990		415,148,990	2
97		13,943		13,943	3
225		8,970		8,970	4
1,096		45,088		45,088	5
10,400		352,680		352,680	6
400		10,800		10,800	7
	33			33	8
		-253	-566	-819	9
12,400		318,200		318,200	10
223,756		6,090,480		6,090,480	11
160,411		3,992,134	4,170,649	8,162,783	12
1,600		45,000		45,000	13
1,600		38,400		38,400	14
0	0	0	0	0	
13,790,851	33	426,192,298	4,170,083	430,362,414	
13,790,851	**33**	**426,192,298**	**4,170,083**	**430,362,414**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
800		20,000		20,000	1
2,000		84,600		84,600	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
13,790,851	33	426,192,298	4,170,083	430,362,414	
13,790,851	**33**	**426,192,298**	**4,170,083**	**430,362,414**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	1,788,323	2,010,154
5	(501) Fuel	91,381,379	126,727,159
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	235,768	256,102
10	(506) Miscellaneous Steam Power Expenses	8,347,313	7,775,598
11	(507) Rents	27,061	11,635
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	101,779,844	136,780,648
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	238	12,217
16	(511) Maintenance of Structures	337,782	103,928
17	(512) Maintenance of Boiler Plant	2,321,208	3,118,185
18	(513) Maintenance of Electric Plant	309,700	583,166
19	(514) Maintenance of Miscellaneous Steam Plant	3,317,484	8,247,335
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	6,286,412	12,064,831
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	108,066,256	148,845,479
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	325,869	-497,275
25	(518) Fuel		
26	(519) Coolants and Water		-7,878
27	(520) Steam Expenses	9,869	78,032
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	829,989	2,154,769
32	(525) Rents		-9,528
33	TOTAL Operation (Enter Total of lines 24 thru 32)	1,165,727	1,718,120
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	248,915	-7,960,088
36	(529) Maintenance of Structures		1,730
37	(530) Maintenance of Reactor Plant Equipment		5,294
38	(531) Maintenance of Electric Plant	731	92
39	(532) Maintenance of Miscellaneous Nuclear Plant	192,545	-240,964
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	442,191	-8,193,936
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	1,607,918	-6,475,816
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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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	446,693	1,363,263
63	(547) Fuel	4,218,680	2,864,536
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses	8,536,469	9,144,492
66	(550) Rents		690
67	TOTAL Operation (Enter Total of lines 62 thru 66)	13,201,842	13,372,981
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	794	182
70	(552) Maintenance of Structures	25,012	-19,038
71	(553) Maintenance of Generating and Electric Plant	7,836,538	14,225,946
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	9,518,929	5,871,410
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	17,381,273	20,078,500
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	30,583,115	33,451,481
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,589,224,779	1,671,028,598
77	(556) System Control and Load Dispatching	3,267,145	3,324,194
78	(557) Other Expenses	6,949,874	7,426,768
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,599,441,798	1,681,779,560
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,739,699,087	1,857,600,704
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,744,285	7,142,785
84			
85	(561.1) Load Dispatch-Reliability	608,045	599,703
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,321,142	1,475,760
87	(561.3) Load Dispatch-Transmission Service and Scheduling	197,927	227,063
88	(561.4) Scheduling, System Control and Dispatch Services	5,906,075	6,718,848
89	(561.5) Reliability, Planning and Standards Development	410,126	422,813
90	(561.6) Transmission Service Studies		6,044
91	(561.7) Generation Interconnection Studies	29,157	4,276
92	(561.8) Reliability, Planning and Standards Development Services	3,294,992	3,613,237
93	(562) Station Expenses	5,968,735	4,305,577
94	(563) Overhead Lines Expenses	5,140,720	4,849,653
95	(564) Underground Lines Expenses	7,547	424
96	(565) Transmission of Electricity by Others	439	
97	(566) Miscellaneous Transmission Expenses	20,855,545	23,510,103
98	(567) Rents	2,507,242	1,616,947
99	TOTAL Operation (Enter Total of lines 83 thru 98)	53,991,977	54,493,233
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,492,109	974,742
102	(569) Maintenance of Structures		543
103	(569.1) Maintenance of Computer Hardware	1,307,433	1,501,017
104	(569.2) Maintenance of Computer Software	2,296,360	2,865,486
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	368,982	200,638
107	(570) Maintenance of Station Equipment	10,303,297	6,431,297
108	(571) Maintenance of Overhead Lines	17,759,358	18,438,916
109	(572) Maintenance of Underground Lines	355,128	416,793
110	(573) Maintenance of Miscellaneous Transmission Plant	1,917	18,432
111	TOTAL Maintenance (Total of lines 101 thru 110)	33,884,584	30,847,864
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	87,876,561	85,341,097

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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	3,365,163	3,878,238
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,365,163	3,878,238
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)	3,365,163	3,878,238
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	18,188,602	20,261,619
135	(581) Load Dispatching	2,843,727	3,676,353
136	(582) Station Expenses	5,313,914	4,910,017
137	(583) Overhead Line Expenses	3,088,786	2,427,310
138	(584) Underground Line Expenses	3,049,553	2,533,843
139	(585) Street Lighting and Signal System Expenses	590,079	621,671
140	(586) Meter Expenses	10,905,267	10,722,449
141	(587) Customer Installations Expenses	6,567,025	5,793,072
142	(588) Miscellaneous Expenses	28,855,925	32,837,817
143	(589) Rents	462,486	476,435
144	TOTAL Operation (Enter Total of lines 134 thru 143)	79,865,364	84,260,586
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,474,963	1,479,120
147	(591) Maintenance of Structures	1,141	187,155
148	(592) Maintenance of Station Equipment	2,248,185	3,345,319
149	(593) Maintenance of Overhead Lines	45,182,924	41,183,868
150	(594) Maintenance of Underground Lines	9,520,845	9,104,513
151	(595) Maintenance of Line Transformers	11,091	15,925
152	(596) Maintenance of Street Lighting and Signal Systems	124,470	86,230
153	(597) Maintenance of Meters	1,895,444	1,512,087
154	(598) Maintenance of Miscellaneous Distribution Plant	706,540	267,268
155	TOTAL Maintenance (Total of lines 146 thru 154)	61,165,603	57,181,485
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	141,030,967	141,442,071
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	2,300,358	2,440,923
161	(903) Customer Records and Collection Expenses	37,124,281	37,914,774
162	(904) Uncollectible Accounts	4,448,897	4,860,860
163	(905) Miscellaneous Customer Accounts Expenses	236,979	236,372
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	44,110,515	45,452,929

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	31,764	26,307
168	(908) Customer Assistance Expenses	203,952,339	170,684,028
169	(909) Informational and Instructional Expenses	105,190	146,527
170	(910) Miscellaneous Customer Service and Informational Expenses	3,916,094	2,525,878
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	208,005,387	173,382,740
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	30,638,332	29,373,126
182	(921) Office Supplies and Expenses	8,501,761	-15,156,779
183	(Less) (922) Administrative Expenses Transferred-Credit	7,494,244	9,451,453
184	(923) Outside Services Employed	93,114,129	142,156,284
185	(924) Property Insurance	4,342,028	4,752,704
186	(925) Injuries and Damages	87,830,779	101,140,890
187	(926) Employee Pensions and Benefits	32,700,832	31,678,317
188	(927) Franchise Requirements	114,077,380	125,260,417
189	(928) Regulatory Commission Expenses	17,195,211	15,618,351
190	(929) (Less) Duplicate Charges-Cr.	2,227,412	2,166,846
191	(930.1) General Advertising Expenses	153,179	136,091
192	(930.2) Miscellaneous General Expenses	1,497,543	11,973,407
193	(931) Rents	11,234,212	11,131,728
194	TOTAL Operation (Enter Total of lines 181 thru 193)	391,563,730	446,446,237
195	Maintenance		
196	(935) Maintenance of General Plant	8,607,842	8,996,726
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	400,171,572	455,442,963
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,624,259,252	2,762,540,742

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arlington Valley Solar I LLC	LU	FERC Vol. 10			
2	Applied Energy Inc	LU	FERC Vol. 10			
3	Avangrid Renewables LLC	LU	FERC Vol. 10			
4	California ISO					
5	Calipatria LLC	LU	FERC Vol. 10			
6	Calpeak Power LLC	OS				
7	Calpine Energy Services, L.P.	IF	FERC Vol. 10			
8	Campo Verde Solar LLC	LU	FERC Vol. 10			
9	Cascade Solar LLC	LU	FERC Vol. 10			
10	Catalina Solar LLC	LU	FERC Vol. 10			
11	Centinela Solar Energy LLC	LU	FERC Vol. 10			
12	Centinela Solar Energy 2 LLC	LU	FERC Vol. 10			
13	City of Escondido	LU	FERC Vol. 10			
14	City of Oceanside	LU	FERC Vol. 10			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of San Diego - Pt. Loma	LU	FERC Vol. 10			
2	Coram Energy LLC	LU	FERC Vol. 10			
3	Covanta Delano Inc	LU	FERC Vol. 10			
4	CP Kelco US Inc	LU	FERC Vol. 10			
5	CSolar IV South	LU	FERC Vol. 10			
6	CSolar IV West	LU	FERC Vol. 10			
7	Desert Green Solar Farm LLC	LU	FERC Vol. 10			
8	Dynegy Power Mktg Inc	AD	FERC Vol. 10			
9	El Cajon Energy Center (Tolling)	LU	FERC Vol. 10			
10	Energia Sierra Juarez	LU	FERC Vol. 10			
11	EnerNoc Inc	LU	FERC Vol. 10			
12	Escondido Energy Center LLC	LU	FERC Vol. 10			
13	FPL Energy Green Power Wind, LLC	LU	FERC Vol. 10			
14	Gas Recovery Systems	LU	FERC Vol. 10			
	Total					

Name of Respondent San Diego Gas & Electric 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

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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Goal Line LP	LU	FERC Vol. 10			
2	Grossmont Hospital Corporation	LU	FERC Vol. 10			
3	Imperial Valley Solar I LLC	LU	FERC Vol. 10			
4	Kumeyaay Wind LLC	LU	FERC Vol. 10			
5	Maricopa West Solar PV LLC	LU	FERC Vol. 10			
6	MM Prima Deshecha Energy LLC	LU	FERC Vol. 10			
7	MM San Diego LLC	LU	FERC Vol. 10			
8	Naturener Glacier Wind Energy 1 LLC	EX				
9	Naturener Glacier Wind Energy 2 LLC	EX				
10	Naturener Rim Rock Wind Energy LLC	EX				
11	NLP Valley Center	LU	FERC Vol. 10			
12	NLP Granger A82 LLC	LU	FERC Vol. 10			
13	NRG Solar Borrego LLC	LU	FERC Vol. 10			
14	Oak Creek Wind Power LLC	LU	FERC Vol. 10			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Oasis Power Partners LLC	LU	FERC Vol. 10			
2	Ocotillo Express LLC	LU	FERC Vol. 10			
3	Olivenhain Muni Water District	LU	FERC Vol. 10			
4	Orange Grove Energy Center (Tolling)	LU	FERC Vol. 10			
5	Otay Landfill Gas LLC	LU	FERC Vol. 10			
6	Otay Mesa Energy Center (Tolling)	LU	FERC Vol. 10			
7	Pacific Wind Lessee LLC	LU	FERC Vol. 10			
8	Pico Pico Energy Center	LU	FERC Vol. 10			
9	San Diego County Water Authority (Hod)	LU	FERC Vol. 10			
10	San Diego County Water Authority (PQ)	LU	FERC Vol. 10			
11	San Gorgonio Westwinds II, LLC	LU	FERC Vol. 10			
12	San Marcos Energy LLC	LU	FERC Vol. 10			
13	SG2 Imperial Valley LLC	LU	FERC Vol. 10			
14	Sol Orchard 20 LLC	LU	FERC Vol. 10			
	Total					

Name of Respondent San Diego Gas & Electric 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

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Sol Orchard 21 LLC	LU	FERC Vol. 10			
2	Sol Orchard 22 LLC	LU	FERC Vol. 10			
3	Sol Orchard 23 LLC	LU	FERC Vol. 10			
4	Sycamore Energy 1 LLC	LU	FERC Vol. 10			
5	Sycamore Energy 2 LLC	LU	FERC Vol. 10			
6	Tallbear Seville LLC	LU	FERC Vol. 10			
7	Yuma Co-generator Association	LU	FERC Vol. 10			
8	Anahau Energy LLC	SF	FERC Vol. 10			
9	BP Energy Company	SF	FERC Vol. 10			
10	Calpine Energy Services, L.P.	SF	FERC Vol. 10			
11	Cargill Power Markets LLC	SF	FERC Vol. 10			
12	City of Anaheim	SF	FERC Vol. 10			
13	Morgan Stanley Capital Group Inc	SF	FERC Vol. 10			
14	NRG Power Marketing LLC	SF	FERC Vol. 10			
	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.
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1	Powerex Corporation	SF	FERC Vol. 10			
2	Santa Fe Irrigation District	LU	FERC Vol. 10			
3	Shell Energy North America (US) LP	SF	FERC Vol. 10			
4	Broker Fees	OS				
5	Hedging Activity	OS				
6	Re-MAT Program Fee	OS				
7	GHG Allowances	OS				
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)	
375,295			-1,036	43,281,547	1,165,468	44,445,979	1
813,408			18,922,278	24,876,839		43,799,117	2
370,512				23,053,597	612,674	23,666,271	3
16,698,765				545,795,218	-14,446,139	531,349,079	4
48,741				3,471,352	69,718	3,541,070	5
			5,760,000			5,760,000	6
							7
362,328			12,669	42,172,322	-36,236	42,148,755	8
54,692				4,112,099	-5,498	4,106,601	9
270,786			17,647	34,966,113	-29,304	34,954,456	10
378,192				49,908,911	2,594,253	52,503,164	11
134,917				17,217,281	896,235	18,113,516	12
805			8,176	25,477		33,653	13
127			291	4,633		4,924	14
27,138,613	1,240,176	1,240,176	207,313,163	1,318,774,315	63,137,301	1,589,224,779	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
19,036			-525	1,455,699		1,455,174	1
28,236			-185	2,761,833	-2,635	2,759,013	2
				3,667		3,667	3
12,184			56,210	367,594		423,804	4
313,741			11,433	41,216,973	2,702,362	43,930,768	5
418,114			11,131	41,185,831	1,411,133	42,608,095	6
14,189			531	1,979,429	-1,419	1,978,541	7
							8
10,340			6,944,943	753,664		7,698,607	9
422,821			7,026	44,317,347	-42,282	44,282,091	10
			1,759,609			1,759,609	11
31,847			7,209,357	1,700,866		8,910,223	12
25,145				1,446,452		1,446,452	13
							14
27,138,613	1,240,176	1,240,176	207,313,163	1,318,774,315	63,137,301	1,589,224,779	

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)	
23,017			10,850,655	1,181,101		12,031,756	1
			2	16		18	2
567,665			34,077	64,448,997	2,594,276	67,077,350	3
134,342				7,306,957		7,306,957	4
52,567			976	3,407,666	-5,138	3,403,504	5
45,175			8,477	2,687,089		2,695,566	6
30,474			220	2,682,281		2,682,501	7
	287,440	287,440		5,880,924		5,880,924	8
	293,237	293,237		8,624,250		8,624,250	9
	659,499	659,499		-9,876,333		-9,876,333	10
213				6,471	-21	6,450	11
1,978				190,558	-198	190,360	12
71,084			5,146	10,316,046	-7,108	10,314,084	13
6,222			170	410,118	-540	409,748	14
27,138,613	1,240,176	1,240,176	207,313,163	1,318,774,315	63,137,301	1,589,224,779	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	
186,056				9,981,228		9,981,228	1
529,478			13,285	55,012,040	-52,948	54,972,377	2
210				32,234		32,234	3
42,128			16,487,909	1,803,237		18,291,146	4
42,639				4,211,632		4,211,632	5
2,666,807			70,350,852	74,811,740	-5,165,837	139,996,755	6
328,829			8,608	37,969,754	-32,883	37,945,479	7
					-590,600	-590,600	8
-10,167			2,732,375	268,016		3,000,391	9
8,951				469,691		469,691	10
17,898			-43,642	1,312,110	-1,629	1,266,839	11
12,787			314	1,499,768		1,500,082	12
423,086			99,313	37,135,225	1,304,516	38,539,054	13
4,857			17,529	606,881	-486	623,924	14
27,138,613	1,240,176	1,240,176	207,313,163	1,318,774,315	63,137,301	1,589,224,779	

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)	
11,767			883	1,517,634	-1,178	1,517,339	1
6,196			425	796,418	-620	796,223	2
11,599			890	1,497,401	-1,160	1,497,131	3
5,798			-1,339	683,122		681,783	4
14,907			248	1,319,099		1,319,347	5
61,528				5,338,346	110,506	5,448,852	6
11,205			9,983,770	508,587		10,492,357	7
			186,000			186,000	8
150,144				15,014,400		15,014,400	9
			195,003			195,003	10
400				20,400		20,400	11
15				420		420	12
651,612				36,695,469		36,695,469	13
			55,092,790			55,092,790	14
27,138,613	1,240,176	1,240,176	207,313,163	1,318,774,315	63,137,301	1,589,224,779	

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)	
			364,000			364,000	1
525			16,672	16,837		33,509	2
222,400			188,000	6,911,741		7,099,741	3
					256,769	256,769	4
					36,395,253	36,395,253	5
					2,565	2,565	6
					33,445,432	33,445,432	7
							8
							9
							10
							11
							12
							13
							14
27,138,613	1,240,176	1,240,176	207,313,163	1,318,774,315	63,137,301	1,589,224,779	

Name of Respondent San Diego Gas & Electric 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 456.1)
(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 Classification (d)
1	CAISO	N/A	N/A	OS
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				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
001	N/A	N/A				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
			0	**0**	**0**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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.
	258,199,601		258,199,601	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
0	**258,199,601**	**0**	**258,199,601**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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					
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32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	889,784
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	145,828
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	412,906
6	Fleet MTM & True-up	-714,792
7	FERC Audit Adjustments	586,936
8	Cost of Financing	176,881
9		
10		
11		
12		
13		
14		
15		
16		
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44		
45		
46	TOTAL	1,497,543

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			23,855,697		23,855,697
2	Steam Production Plant	19,959,325				19,959,325
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	20,940,829			2,148	20,942,977
7	Transmission Plant	125,144,577			1,891,120	127,035,697
8	Distribution Plant	219,537,273			1,896,092	221,433,365
9	Regional Transmission and Market Operation					
10	General Plant	14,880,388				14,880,388
11	Common Plant-Electric	26,344,848		33,802,525		60,147,373
12	TOTAL	426,807,240		57,658,222	3,789,360	488,254,822

B. Basis for Amortization Charges

Account 404
The amortization of Intangible Plant (software) is based on the anticipated useful life of the software project.

Account 405
The amortization of Land Rights is based on the anticipated useful lives of the rights-of-way.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	STEAM PRODUCTION						
13	311-Desert Star	29,031	23.60	-6.00	4.10	Iowa Type SQ	13.50
14	311-Palomar	58,449	27.60	-18.00	4.36	Iowa Type SQ	20.50
15	312-Desert Star	49,418	23.60	-6.00	4.37	Iowa Type SQ	13.50
16	312-Palomar	106,700	29.90	-10.00	3.67	Iowa Type SQ	20.50
17	314-Desert Star	14,405	20.80	-6.00	5.29	Iowa Type SQ	13.50
18	314-Palomar	111,954	28.80	-2.00	3.53	Iowa Type SQ	20.50
19	315-Desert Star	46,263	22.70	-6.00	4.84	Iowa Type SQ	13.50
20	315-Palomar	37,254	29.20	-2.00	3.49	Iowa Type SQ	20.50
21	316-Desert Star	4,554	20.90	-6.00	5.41	Iowa Type SQ	13.50
22	316-Palomar	40,215	26.30	-3.00	4.08	Iowa Type SQ	20.50
23	SUBTOTAL	498,243					
24							
25	OTHER PRODUCTION						
26	341-CPEP	1,865	14.20	-1.00	7.44	Iowa Type SQ	11.50
27	341-Desert Star	1,751	21.00	-6.00	5.21	Iowa Type SQ	13.50
28	341-Miramar	5,076	23.30	-1.00	4.43	Iowa Type SQ	16.50
29	341-Palomar	14,011	28.30	-1.00	3.56	Iowa Type SQ	20.50
30	342-CPEP	583	15.00	-2.00	7.05	Iowa Type SQ	11.50
31	342-Desert Star	594	24.30	-6.00	4.20	Iowa Type SQ	13.50
32	342-Miramar	5,233	24.00	-2.00	4.46	Iowa Type SQ	16.50
33	342-Palomar	14,060	30.00	-2.00	3.31	Iowa Type SQ	20.50
34	343-CPEP	9,986	15.00		6.77	Iowa Type SQ	11.50
35	343-Desert Star	23,864	23.60	-6.00	4.43	Iowa Type SQ	13.50
36	343-Miramar	53,362	24.40		4.06	Iowa Type SQ	16.50
37	343-Palomar		20.00			Iowa Type SQ	
38	344-CPEP	1,978	14.60	-0.50	7.18	Iowa Type SQ	11.50
39	344-Desert Star	108,119	23.20	-6.00	4.11	Iowa Type SQ	13.50
40	344-Miramar	19,736	22.00	-0.50	4.83	Iowa Type SQ	16.50
41	344-Palomar	170,416	29.70	-0.50	3.46	Iowa Type SQ	20.00
42	344-Solar	40,807	25.00		4.00	Iowa Type SQ	20.10
43	344-Wind	257	20.00		5.03	Iowa Type SQ	17.50
44	345-CPEP	834	15.00	-2.00	7.08	Iowa Type SQ	11.50
45	345-Desert Star	9,194	23.30	-7.00	4.46	Iowa Type SQ	13.50
46	345-Miramar	13,457	24.10	-2.00	4.33	Iowa Type SQ	16.50
47	345-Palomar	6,707	27.40	-2.00	3.58	Iowa Type SQ	20.50
48	345-Solar	2,316	25.00		3.95	Iowa Type SQ	17.60
49	345-Wind		20.00		5.00	Iowa Type SQ	
50	346-CPEP	715	14.60		6.98	Iowa Type SQ	11.50

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	346-Desert Star	22,342	24.30	-6.00	4.01	Iowa Type SQ	13.50
13	346-Miramar	3,116	19.50		5.31	Iowa Type SQ	16.50
14	346-Palomar	1	22.00		4.52	Iowa Type SQ	20.50
15	SUBTOTAL	530,380					
16							
17	TRANSMISSION-SWPL						
18	352	12,818	72.00	-60.00	1.62	Iowa Type R2	47.40
19	353	219,916	50.00	-60.00	4.02	Iowa Type R1	40.20
20	354	61,988	70.00	-100.00	2.65	Iowa Type R5	38.50
21	355	10,190	45.00	-100.00	5.08	Iowa Type R1.5	26.60
22	356	46,247	58.00	-100.00	1.77	Iowa Type S0	37.90
23	359	5,324	60.00		1.44	Iowa Type SQ	33.60
24	SUBTOTAL	356,483					
25							
26	TRANSMISSION-SRPL						
27	352	121,021	72.00		1.39	Iowa Type R2	68.90
28	353	161,536	50.00		2.01	Iowa Type R1	47.50
29	354	767,274	70.00		1.47	Iowa Type R5	66.50
30	355	3,437	45.00		2.26	Iowa Type R1.5	42.10
31	356	173,598	58.00		1.75	Iowa Type S0	54.80
32	357	80,502	60.00		1.69	Iowa Type R5	56.50
33	358	126,452	50.00		2.02	Iowa Type R3	46.60
34	359	227,866	60.00		1.68	Iowa Type SQ	56.50
35	SUBTOTAL	1,661,686					
36							
37	TRANSMISSION-OTHER						
38	352	314,801	72.00	-60.00	2.18	Iowa Type R2	66.20
39	353	956,489	50.00	-60.00	3.52	Iowa Type R1	43.50
40	353.4	1,420	50.00	-60.00	3.25	Iowa Type R1	42.40
41	354	66,270	70.00	-100.00	3.13	Iowa Type R5	50.10
42	355	427,768	45.00	-100.00	4.65	Iowa Type R1.5	40.00
43	356	336,378	58.00	-100.00	3.20	Iowa Type S0	48.90
44	357	265,053	60.00	-45.00	2.43	Iowa Type R5	53.30
45	358	238,076	50.00	-10.00	2.08	Iowa Type R3	43.80
46	359	77,244	60.00		1.65	Iowa Type SQ	54.30
47	SUBTOTAL	2,683,499					
48							
49	DISTRIBUTION						
50	361	4,104	63.00	-125.00	3.84	Iowa Type R2.5	46.90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	362.1	489,784	51.00	-125.00	4.80	Iowa Type R1.5	40.50
13	363	37,906	10.00		10.27	Iowa Type SQ	9.00
14	364	655,048	47.00	-100.00	4.09	Iowa Type R0.5	39.00
15	365	588,074	55.00	-70.00	2.85	Iowa Type R0.5	47.30
16	366	1,138,256	57.00	-50.00	2.62	Iowa Type R3	42.10
17	367	1,447,552	45.00	-65.00	3.35	Iowa Type R3	31.40
18	368.1	583,024	34.00	-70.00	5.59	Iowa Type L0.5	26.60
19	368.2	30,414	12.00	-70.00	20.18	Iowa Type L0	8.80
20	369.1	140,862	55.00	-110.00	2.68	Iowa Type R0.5	45.00
21	369.2	337,934	53.00	-75.00	2.93	Iowa Type L4	35.80
22	370.1	3,237	48.00		2.02	Iowa Type R0.5	44.10
23	370.11	189,466	15.00		6.66	Iowa Type SQ	9.80
24	E370.20	5,174	48.00		2.06	Iowa Type R0.5	46.60
25	E370.21	50,530	15.00		6.67	Iowa Type SQ	10.10
26	E371.00	8,267	34.00	-90.00	2.47	Iowa Type R0.5	22.60
27	E373.20	28,657	36.00	-85.00	4.44	Iowa Type L0	
28	SUBTOTAL	5,738,289					
29							
30	GENERAL						
31	390	33,083	34.00	-10.00	2.12	Iowa Type S4	17.20
32	392.2	58	27.00		4.43	Iowa Type L5	18.30
33	393.1	9	25.00		1.69	Iowa Type S5	2.50
34	394.11	24,391	27.00		3.74	Iowa Type S6	17.90
35	394.2	341	26.00		3.09	Iowa Type L4	9.30
36	395.1	5,153	22.00		4.64	Iowa Type L3	20.60
37	397.1	237,890	30.00	-50.00	4.99	Iowa Type R2	22.60
38	397.2	6,917	30.00	-50.00	4.92	Iowa Type R2	14.80
39	397.6	9,110	30.00		5.01	Iowa Type R2	26.90
40	397.7	25	30.00	-50.00	5.01	Iowa Type R2	29.60
41	398.1	5,488	16.00		6.18	Iowa Type L4	13.80
42	SUBTOTAL	322,465					
43							
44	TOTAL	11,791,045					
45							
46	SEE FOOTNOTE						
47							
48							
49							
50							

Schedule Page: 336 Line No.: 12 Column: f

Reclassification of 2015 Electric Depreciation and Amortization Charges
Depreciation and Amortization Expense Charged in Accordance with FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	Depreciation Expense (Account 403)	Amortization of Limited Term Electric Plant (Account 404)	Amortization of Other Electric Plant (Account 405)	Total
Intangible Plant	-	23,855,697	-	23,855,697
Steam Production	20,429,972	-	-	20,429,972
Nuclear Production	-	-	-	-
Other Production	19,210,811	-	-	19,210,811
Transmission Plant	123,603,632	-	1,882,524	125,486,156
Distribution Plant	222,337,589	-	1,906,836	224,244,425
General Plant	14,880,388	-	-	14,880,388
Common Plant-Electric	26,344,848	33,802,525	-	60,147,373
Total Ratemaking Depreciation & Amort.	426,807,240	57,658,222	3,789,360	488,254,822

Schedule Page: 336.2 Line No.: 46 Column: b

Depreciable Plant Base (In Thousands) shown as weighted plant calculated through the quotient of depreciation expense, inclusive of Net Salvage, and annual depreciation rate.

Schedule Page: 336.2 Line No.: 46 Column: c

Estimated Avg. Service Life for the CPEP, Desert Star, Palomar, and Miramar, generating facilities represents the cost-weighted difference between in-service dates and the decommissioning date for each plant at the beginning of the year. It is provided for informational purposes only.

Schedule Page: 336.2 Line No.: 46 Column: d

Depreciation parameters based upon 2016 California Public Utilities Commission D. 16-06-054.

Schedule Page: 336.2 Line No.: 46 Column: g

Average Remaining Life represents the calculated expectancy, or cost-weighted average remaining life, for assets in service at the beginning of 2016 based upon the specified depreciation parameters of mortality curve, average service life / decommissioning date.

Name of Respondent San Diego Gas & Electric 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	D. 15-12-040 RESIDENTIAL RATE STRUCTURES		31,992	31,992	
2			4,247	4,247	
3					
4	D. 15-12-044 PURCHASE POWER TOLLING AGMT		83,791	83,791	
5					
6	D. 15-12-045 PURCHASE POWER TOLLING AGMT		22,839	22,839	
7					
8	D. 16-01-022 RESIDENTIAL RATE STRUCTURES		44,764	44,764	
9					
10	D.16-01-040 SMARTMETER PROGRAM		169	169	
11			22	22	
12					
13	D. 16-01-041 RESIDENTIAL RATE STRUCTURES		18,543	18,543	
14			2,461	2,461	
15					
16	D. 16-01-042 RESIDENTIAL RATE STRUCTURES		25,444	25,444	
17			4,182	4,182	
18					
19	D 16-01-043 INTEGRATED DISTRIBUTED ENERGY		1,814	1,814	
20			241	241	
21					
22	D. 16-02-023 ENERGY EFFICIENCY PROGRAMS		7,161	7,161	
23			951	951	
24					
25	D. 16-03-023 PURCHASE POWER TOLLING AGMT		6,240	6,240	
26					
27	D. 16-04-010 WATER ENERGY NEXUS PROGRAM		3,784	3,784	
28			445	445	
29					
30	D. 16-04-029 SMARTMETER PROGRAM		2,584	2,584	
31			359	359	
32					
33	D. 16-04-032 INTERCONNECTION RULES		2,320	2,320	
34			381	381	
35					
36	D. 16-04-033 COMMERCIAL MOBILE RADIO SERVICE		7,873	7,873	
37					
38	D. 16-04-036 JOINT RELIABILITY PLAN		1,833	1,833	
39					
40	D. 16-04-037 MKTG,EDU, OUTREACH PROGRAM		1,050	1,050	
41			124	124	
42					
43	D. 16-04-038 "CARE"		5,439	5,439	
44			894	894	
45					
46	TOTAL	6,760,925	14,153,597	20,914,522	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	D. 16-05-018 RELIABILITY REPORTING		1,782	1,782	
2			210	210	
3					
4	D. 16-05-020 ENERGY STORAGE PROCUREMENT		4,681	4,681	
5			551	551	
6					
7	D. 16-05-021 TRIENNIAL COST ALLOCATION		24,010	24,010	
8			2,825	2,825	
9					
10	D. 16-05-045 UPDATE ELECTRIC RATE DESIGN		50,991	50,991	
11					
12	D. 16-05-046 NET ENERGY METERING		7,556	7,556	
13					
14	D. 16-05-047 NET ENERGY METERING		12,214	12,214	
15					
16	D. 16-05-048 NET ENERGY METERING		919	919	
17					
18	D. 16-05-049 NET ENERGY METERING		4,989	4,989	
19					
20	D. 16-06-022 SAN ONOFRE NUCLEAR GEN STATION		45,014	45,014	
21					
22	D. 16-06-023 NET ENERGY METERING		2,755	2,755	
23					
24	D. 16-06-024 NET ENERGY METERING		23,652	23,652	
25					
26	D. 16-06-025 ALT-FULED VEHICLE TARIFFS		142,642	142,642	
27					
28	D. 16-06-026 VEHICLE GRID INTEGRATION		32,254	32,254	
29					
30	D. 16-06-027 ENERGY STORAGE PROCUREMENT		4,035	4,035	
31			475	475	
32					
33	D. 16-06-028 VEHICLE GRID INTEGRATION		210,825	210,825	
34					
35	D. 16-06-049 ALT-FULED VEHICLE TARIFFS		83,453	83,453	
36			9,819	9,819	
37					
38	D. 16-06-050 ALT-FULED VEHICLE TARIFFS		115,634	115,634	
39					
40	D. 16-06-051 TRIENNIAL COST ALLOCATION		8,730	8,730	
41			1,027	1,027	
42					
43	D. 16-07-010 SAN ONOFRE NUCLEAR GEN STATION		15,024	15,024	
44			2,469	2,469	
45					
46	TOTAL	6,760,925	14,153,597	20,914,522	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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					
2	D. 16-07-011 ALT-FULED VEHICLE TARIFFS		244,063	244,063	
3			28,716	28,716	
4					
5	D. 16-07-013 DYNAMIC PRICING		50,911	50,911	
6					
7	D.16-07-019 SMARTMETER PROGRAM		169	169	
8			23	23	
9					
10	D. 16-08-14 ENERGY STORAGE PROCURMENT		3,210	3,210	
11			378	378	
12					
13	D. 16-08-015 MKTG, EDU & OUTREACH PROGRAM		1,215	1,215	
14			143	143	
15					
16	D. 16-08-016 DISTRIBUTED GENERATION		929	929	
17			153	153	
18					
19	D. 16-09-028 SOLAR GENERATED ELEC ACCESS		3,188	3,188	
20					
21	D. 16-09-029 SOLAR GENERATED ELEC ACCESS		4,067	4,067	
22					
23	D.16-09-030 SOLAR GENERATED ELEC ACCESS		28,708	28,708	
24					
25	D. 16-09-054 SOLAR GENERATED ELEC ACCESS		25,140	25,140	
26					
27	D. 16-10-012 INTEGRATED DISTRIBUTED ENERGY		1,029	1,029	
28			121	121	
29					
30	D. 16-10-013 RESIDENTIAL RATE STRUCTURES		22,472	22,472	
31			2,644	2,644	
32					
33	D.16-10-014 INCREASE RATES AND CHARGES		60,061	60,061	
34			7,067	7,067	
35					
36	D. 16-10-015 PROCUREMENT POLICIES		9,649	9,649	
37					
38	D. 16-10-016 PROCUREMENT POLICIES		15,834	15,834	
39					
40	D. 16-10-017 INCREASE RATES AND CHARGES		27,958	27,958	
41			3,289	3,289	
42					
43	D. 16-10-031 RESIDENTIAL RATE STRUCTURES		28,683	28,683	
44					
45					
46	TOTAL	6,760,925	14,153,597	20,914,522	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	D. 16-10-033 INCREASE RATES AND CHARGES		134,713	134,713	
2			15,850	15,850	
3					
4	D.16-10-034 INCREASE RATES AND CHARGES		22,497	22,497	
5			2,647	2,647	
6					
7	D. 16-10-035 INCREASE RATES AND CHARGES		90,153	90,153	
8			10,607	10,607	
9					
10	D. 16-11-004 INCREASE RATES AND CHARGES		235,984	235,984	
11			27,766	27,766	
12					
13	D.16-11-016 TRIENNIAL COST ALLOCATION		4,189	4,189	
14					
15	D.16-11-017 INTERCONNECTION RULES		18,838	18,838	
16			3,096	3,096	
17					
18	D. 16-11-018 CUSTOMER OUTREACH PLAN		27,788	27,788	
19					
20	D. 16-11-020 CALIFORNIA RENEWABLES		4,309	4,309	
21					
22	CALIFORNIA PUBLIC UTILITIES COMMISSION FEES	6,162,912		6,162,912	
23		598,013		598,013	
24					
25	FERC PROCEEDINGS		43,703	43,703	
26					
27	MISCELLANEOUS		8,853,226	8,853,226	
28			2,997,928	2,997,928	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	6,760,925	14,153,597	20,914,522	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.
Elec	928	31,992					1
Gas	928	4,247					2
							3
Elec	928	83,791					4
							5
Elec	928	22,839					6
							7
Elec	928	44,764					8
							9
Elec	928	169					10
Gas	928	22					11
							12
Elec	928	18,543					13
Gas	928	2,461					14
							15
Elec	928	25,444					16
Gas	928	4,182					17
							18
Elec	928	1,814					19
Gas	928	241					20
							21
Elec	928	7,161					22
Gas	928	951					23
							24
Elec	928	6,240					25
							26
Elec	928	3,784					27
Gas	928	445					28
							29
Elec	928	2,584					30
Gas	928	359					31
							32
Elec	928	2,320					33
Gas	928	381					34
							35
Elec	928	7,873					36
							37
Elec	928	1,833					38
							39
Elec	928	1,050					40
Gas	928	124					41
							42
Elec	928	5,439					43
Gas	928	894					44
							45
		20,914,522					46

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.
Elec	928	1,782					1
Gas	928	210					2
							3
Elec	928	4,681					4
Gas	928	551					5
							6
Elec	928	24,010					7
Gas	928	2,825					8
							9
Elec	928	50,991					10
							11
Elec	928	7,556					12
							13
Elec	928	12,214					14
							15
Elec	928	919					16
							17
Elec	928	4,989					18
							19
Elec	928	45,014					20
							21
Elec	928	2,755					22
							23
Elec	928	23,652					24
							25
Elec	928	142,642					26
							27
Elec	928	32,254					28
							29
Elec	928	4,035					30
Gas	928	475					31
							32
Elec	928	210,825					33
							34
Elec	928	83,453					35
Gas	928	9,819					36
							37
Elec	928	115,634					38
							39
Elec	928	8,730					40
Gas	928	1,027					41
							42
Elec	928	15,024					43
Gas	928	2,469					44
							45
		20,914,522					46

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
Elec	928	244,063					2
Gas	928	28,716					3
							4
Elec	928	50,911					5
							6
Elec	928	169					7
Gas	928	23					8
							9
Elec	928	3,210					10
Gas	928	378					11
							12
Elec	928	1,215					13
Gas	928	143					14
							15
Elec	928	929					16
Gas	928	153					17
							18
Elec	928	3,188					19
							20
Elec	928	4,067					21
							22
Elec	928	28,708					23
							24
Elec	928	25,140					25
							26
Elec	928	1,029					27
Gas	928	121					28
							29
Elec	928	22,472					30
Gas	928	2,644					31
							32
Elec	928	60,061					33
Gas	928	7,067					34
							35
Elec	928	9,649					36
							37
Elec	928	15,834					38
							39
Elec	928	27,958					40
Gas	928	3,289					41
							42
Elec	928	28,683					43
							44
							45
		20,914,522					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.
Elec	928	134,713					1
Gas	928	15,850					2
							3
Elec	928	22,497					4
Gas	928	2,647					5
							6
Elec	928	90,153					7
Gas	928	10,607					8
							9
Elec	928	235,984					10
Gas	928	27,766					11
							12
Gas	928	4,189					13
							14
Elec	928	18,838					15
Gas	928	3,096					16
							17
Elec	928	27,788					18
							19
Elec	928	4,309					20
							21
Elec	928	6,162,912					22
Gas	928	598,013					23
							24
Elec	928	43,703					25
							26
Elec	928	8,853,226					27
Gas	928	2,997,928					28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		20,914,522					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	A. Electric R, D & D Performed Internally	
2		
3	(1) Generation	NONE
4		
5	(2) System Planning, Engineering and Operation	NONE
6		
7	(3) Transmission	NONE
8		
9	(4) Distribution	RD&D Performed Internally
10		
11	(5) Environment	NONE
12		
13	(6) Other	NONE
14		
15	(7) Sub Total Internal Costs Incurred	
16		
17	B. External	
18		
19	(1) Research Support to the Electrical	NONE
20	Research Council or the Electric Power	
21	Research Institute	
22		
23	(2) Research Support to Edison Electric Inst.	NONE
24		
25	(3) Research Support to Nuclear Power Groups	NONE
26		
27	(4) Research Support to Others	CPUC and California Energy Commission
28		
29	(5) Sub Total External Costs Incurred	NONE
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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
					3
					4
					5
					6
					7
					8
1,926,415		588	1,926,415		9
					10
					11
					12
					13
					14
1,926,415			1,926,415		15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
	19,850,713	588	19,850,713		27
					28
	19,850,713		19,850,713		29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	10,655,210		
4	Transmission	11,437,704		
5	Regional Market			
6	Distribution	36,852,274		
7	Customer Accounts	16,156,627		
8	Customer Service and Informational	22,137,253		
9	Sales			
10	Administrative and General	38,499,786		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	135,738,854		
12	Maintenance			
13	Production	1,791,674		
14	Transmission	9,990,236		
15	Regional Market			
16	Distribution	13,270,372		
17	Administrative and General	1,301,116		
18	TOTAL Maintenance (Total of lines 13 thru 17)	26,353,398		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,446,884		
21	Transmission (Enter Total of lines 4 and 14)	21,427,940		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	50,122,646		
24	Customer Accounts (Transcribe from line 7)	16,156,627		
25	Customer Service and Informational (Transcribe from line 8)	22,137,253		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	39,800,902		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	162,092,252	36,695,803	198,788,055
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	83,140		
35	Transmission	2,001,187		
36	Distribution	20,223,596		
37	Customer Accounts	7,815,903		
38	Customer Service and Informational	2,690,510		
39	Sales			
40	Administrative and General	12,677,857		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	45,492,193		
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	3,145,193		

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	5,635,759		
49	Administrative and General	426,433		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	9,207,385		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	83,140		
56	Transmission (Lines 35 and 47)	5,146,380		
57	Distribution (Lines 36 and 48)	25,859,355		
58	Customer Accounts (Line 37)	7,815,903		
59	Customer Service and Informational (Line 38)	2,690,510		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	13,104,290		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	54,699,578	11,048,362	65,747,940
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	216,791,830	47,744,165	264,535,995
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	62,390,479	101,506,852	163,897,331
69	Gas Plant	13,340,758	17,510,668	30,851,426
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	75,731,237	119,017,520	194,748,757
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,805,195	11,833,869	21,639,064
74	Gas Plant	505,204	333,927	839,131
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	10,310,399	12,167,796	22,478,195
77	Other Accounts (Specify, provide details in footnote):			
78	3rd Party Billings, Gas	8,197	1,288,015	1,296,212
79	3rd Party Billings, Electric	718,388	4,360,602	5,078,990
80	Affiliate Billings, Gas		8,912,339	8,912,339
81	Affiliate Billings, Electric		27,184,620	27,184,620
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	726,585	41,745,576	42,472,161
96	TOTAL SALARIES AND WAGES	303,560,051	220,675,057	524,235,108

Schedule Page: 354 Line No.: 96 Column: d

FERC 426 is not included in the detail classification lines or summary totals. FERC 426 for 2016 amounts to $801,813.57

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.

Account	Balance Beg. of Year	Additions	Retire From Serv.	Adjs.	Transfers	Balance End of Year
303 Misc. Intangible Plant	324,138,257	69,884,907				394,023,164
389 Land & Land Rights	8,249,876	(223,577)				8,026,299
390 Structures & Improvements	338,543,493	10,498,602	471,650			348,570,445
391 Office Furniture & Equipment	80,424,337	11,004,051	9,425,147			82,003,241
392 Transportation Equipment	46,139	374,323				420,462
393 Stores Equipment	63,971		5,030			58,941
394 Tools, Shop & Garage Equip.	2,541,508	612,871	104,523			3,049,856
395 Laboratory Equipment	1,997,979	124,000	26,524			2,095,455
396 Power Operated Equipmennt						
397 Communication Equipment	194,213,409	3,750,576	9,729,860			188,234,125
398 Miscellaneous Equipment	2,287,819	1,244,214	1,085,404			2,446,629
FIN 47 ARC - Common	3,453,407			854,097		4,307,504
Fleet Capital Lease	20,189,056	581,250	39,513			20,730,793
TOTAL COMMON PLANT	976,149,251	97,851,217	20,887,651	854,097		1,053,966,914
Construction Work in Progress	77,342,798	49,161,081				126,503,879
TOTAL COMMON PLANT	1,053,492,049	147,012,298	20,887,651	854,097		1,180,470,793

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.

ACCOUNT	December 31, 2016 Accumulated Depreciation
303 Misc. Intangible Plant	252,892,419
389 Land & Land Rights	27,776
390 Structures & Improvements	148,905,865
391 Office Furniture & Equipment	45,516,310
392 Transportation Equipment	(288,808)
393 Stores Equipment	45,602
394 Tools, Shop & Garage Equipment	717,021
395 Laboratory Equipment	982,941
396 Power Operated Equipment	(192,979)
397 Communication Equipment	75,536,327
398 Miscellaneous Equipment	462,082
108.4 Retirement Work in Progress	
FIN 47 Accumulated Depreciation	2,240,710
Fleet Capital Lease	20,361,830
Total Accumulated Depreciation	547,207,096

Split of Common Utility Plant to Departments: (excluding CWIP) (see Note 2- Page 356.2)		December 31,2016 Balance End of Year	December 31,2016 Accumulated Depreciation
Electric	75.31%	793,742,483	412,101,664
Gas	24.69%	260,224,431	135,105,432
Total	100.00%	1,053,966,914	547,207,096

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San Diego Gas & Electric 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.

ACCOUNT		Ad Valorem Taxes Note (1)	Depreciation Note (2)
303	Misc. Intangible Plant		44,884,511
389	Land & Land Rights		
390	Structures & Improvements		11,494,181
391	Office Furniture & Equipment		8,829,028
392	Transportation Equipment		45,802
393	Stores Equipment		1,183
394	Tools, Shop & Garage Equipment		182,841
395	Laboratory Equipment		90,706
396	Power Operated Equipment		
397	Communication Equipment		14,263,308
398	Miscellaneous Equipment		74,823
	Total		79,866,383

(1) Ad Valorem Taxes on property are assessed by the State Board of Equalization and consist of one-half of the taxes from each fiscal tax year 2015-2016 and 2016-2017. Ad Valorem Taxes are assessed on the entire operating unit, therefore, assessed taxes are not available by account number. Ad Valorem Taxes are allocated based on procedures adopted by the California Public Utilities Commission.

(2) The Common Utility Plant and Accumulated Depreciation is allocated between the Electric and Gas Departments based on labor ratios in accordance with allocation procedures adopted by the California Public Utilities Commission. These rates were revised in January 2016.
Other expenses of operation, maintenance and rents for common utility plant are allocated based on labor percentage studies. Specific amounts charged to operations and maintenance are not readily available.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	103,328,590	212,686,226	406,875,301	545,795,218
3	Net Sales (Account 447)	(68,459,151)	(145,037,704)	(319,384,065)	(415,148,990)
4	Transmission Rights				
5	Ancillary Services	1,933,042	3,822,225	4,749,555	5,777,021
6	Other Items (list separately)				
7	Congestion	1,041,206	2,522,825	4,077,687	4,086,141
8	CRR (Congestion Revenue Rights)	(6,680,091)	(14,767,567)	(19,498,670)	(31,495,244)
9	GMC (Grid Management Charges)	2,527,364	5,063,164	8,646,324	11,117,020
10	Other	991,517	822,094	3,330,454	5,476,198
11	UFE (Unaccounted for Energy)	1,041,631	1,938,281	(447,117)	2,126,339
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	35,724,108	67,049,544	88,349,469	127,733,703

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	1,331,924	MWH	8,091,775	694,518	MWH	2,314,753
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	1,331,924		8,091,775	694,518		2,314,753

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	3,157	5	17	3,157					
2	February	3,062	16	18	3,062					
3	March	2,902	7	18	2,902					
4	Total for Quarter 1				9,121					
5	April	3,032	18	18	3,032					
6	May	2,763	2	19	2,763					
7	June	4,106	20	15	4,106					
8	Total for Quarter 2				9,901					
9	July	4,320	22	16	4,320					
10	August	4,267	15	16	4,267					
11	September	4,343	26	16	4,343					
12	Total for Quarter 3				12,930					
13	October	3,348	20	17	3,348					
14	November	3,490	9	17	3,490					
15	December	3,064	19	18	3,064					
16	Total for Quarter 4				9,902					
17	Total Year to Date/Year				41,854					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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
San Diego Gas & Electric 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)	15,653,039
3	Steam	3,521,375			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	13,790,851
7	Other	133,067			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	3,654,442	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	33,560
10	Purchases	27,138,613	27	Total Energy Losses	1,315,605
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	30,793,055
12	Received	1,240,176			
13	Delivered	1,240,176			
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	30,793,055			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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: San Diego Gas & Electric

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,324,723	1,075,143	3,157	5	17
30	February	1,140,682	818,735	3,062	16	18
31	March	1,308,164	877,453	2,902	7	18
32	April	1,177,257	692,940	3,032	18	18
33	May	1,116,437	1,242,069	2,763	2	19
34	June	1,220,292	1,161,990	4,106	20	15
35	July	1,201,665	1,656,146	4,320	22	16
36	August	1,721,798	1,846,554	4,267	15	16
37	September	1,455,693	1,506,960	4,343	26	16
38	October	1,418,526	1,117,782	3,348	20	17
39	November	1,286,478	1,058,168	3,490	9	17
40	December	1,281,324	736,911	3,064	19	18
41	TOTAL	15,653,039	13,790,851			

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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: *Palomar* (b)			Plant Name: *Miramar* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Gas Turbine (2)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor			Semi-Outdoor		
3	Year Originally Constructed	2006			2005		
4	Year Last Unit was Installed	2006			2009		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	566.00			96.00		
6	Net Peak Demand on Plant - MW (60 minutes)	566			96		
7	Plant Hours Connected to Load	5584			1852		
8	Net Continuous Plant Capability (Megawatts)	566			96		
9	When Not Limited by Condenser Water	566			96		
10	When Limited by Condenser Water	0			96		
11	Average Number of Employees	29			3		
12	Net Generation, Exclusive of Plant Use - KWh	2296090000			122818000		
13	Cost of Plant: Land and Land Rights	14480000			0		
14	Structures and Improvements	74536954			5075863		
15	Equipment Costs	507865258			96602882		
16	Asset Retirement Costs	0			0		
17	Total Cost	596882212			101678745		
18	Cost per KW of Installed Capacity (line 17/5) Including	1054.5622			1059.1536		
19	Production Expenses: Oper, Supv, & Engr	1163801			0		
20	Fuel	58226404			4218680		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4945195			262878		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	3352812			211415		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	835			0		
30	Maintenance of Structures	370735			5240		
31	Maintenance of Boiler (or reactor) Plant	-32718			0		
32	Maintenance of Electric Plant	7068193			1061198		
33	Maintenance of Misc Steam (or Nuclear) Plant	2331910			7		
34	Total Production Expenses	77427167			5759418		
35	Expenses per Net KWh	0.0337			0.0469		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	15904354	0	0	1245675	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	3.661	0.000	0.000	3.387	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.582	0.000	0.000	3.314	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.000	0.034	0.000	0.000
44	Average BTU per KWh Net Generation	7114.000	0.000	0.000	10416.000	0.000	0.000

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San Diego Gas & Electric 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: *Desert Star* (d)	Plant Name: *Cuyamaca* (e)	Plant Name: (f)	Line No.
Combined Cycle	Gas Turbine		1
Semi-Outdoor	Semi-Outdoor		2
2000	2002		3
2000	2002		4
536.00	47.00	0.00	5
485	47	0	6
8784	204	0	7
450	47	0	8
450	47	0	9
450	47	0	10
23	1	0	11
1225345270	8173000	0	12
0	0	0	13
30877505	1865081	0	14
296323294	14999812	0	15
109537	0	0	16
327310336	16864893	0	17
610.6536	358.8275	0	18
865307	487	0	19
32716112	355023	0	20
0	0	0	21
1803467	13217	0	22
0	0	0	23
0	0	0	24
961942	169151	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	9131	0	30
2840228	0	0	31
8529877	1250829	0	32
1157848	72258	0	33
48874781	1870096	0	34
0.0399	0.2288	0.0000	35

(d)			(e)			(f)			Line No.
GAS			GAS						36
MCF			MCF						37
8948037	0	0	91883	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
3.656	0.000	0.000	3.864	0.000	0.000	0.000	0.000	0.000	41
3.578	0.000	0.000	3.781	0.000	0.000	0.000	0.000	0.000	42
0.027	0.000	0.000	0.043	0.000	0.000	0.000	0.000	0.000	43
7500.000	0.000	0.000	11546.000	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
San Diego Gas & Electric 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. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

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San Diego Gas & Electric 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. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			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
0.0000	0.0000	0.0000	21
			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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

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San Diego Gas & Electric 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. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
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			10
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			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	J&D Labs Fuel Cell	2012	0.40	0.4	2,074	3,002,210
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
7,505,525		83,840		Gas	439	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
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						45
						46

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Miguel	East County	500.00	500.00	3,1s	52.96		1
2	Imperial Valley		500.00	500.00	3	51.50		1
3		Colorado River	500.00	500.00	1S	24.00		1
4	Colorado River	North Gila	500.00	500.00	1S	5.63		1
5	North Gila	Palo Verde	500.00	500.00	3	114.45		1
6	Suncrest	Ocotillo Switchyard	500.00	500.00	3	67.46		1
7	East County	Imperial Valley	500.00	500.00	3,1S	30.94		1
8	Ocotillo Switchyard	Imperial Valley	500.00	500.00	3	21.60		1
9	Ocotillo Switchyard	Ocotillo Express Sub	500.00	500.00	3	0.06		1
10	Total 500KV Pole Line Miles					368.60		9
11	San Luis Rey Tap		230.00	230.00	3		5.29	2
12			230.00	230.00	3	26.45		2
13		Mission	230.00	230.00	2W	3.26		1
14	San Luis Rey		230.00	230.00	3	0.11		1
15			230.00	230.00	2S	0.49		2
16			230.00	230.00	2W	1.00		1
17		San Onofre	230.00	230.00	3	16.26		2
18	San Luis Rey		230.00	230.00	3	5.75		1
19		Encina	230.00	230.00	3	1.47		1
20	San Luis Rey		230.00	230.00	2W	2.34		1
21			230.00	230.00	3		26.58	2
22		Mission	230.00	230.00	2W		3.26	1
23	San Luis Rey	San Onofre	230.00	230.00	3	18.12		2
24	San Onofre		230.00	230.00	2S	0.47		2
25			230.00	230.00	3	6.00		2
26		Talega	230.00	230.00	3	0.43		1
27	San Onofre		230.00	230.00	3		16.82	2
28			230.00	230.00	2W	0.78		1
29			230.00	230.00	1S	0.63		2
30		Encina	230.00	230.00	3		1.90	2
31	Encina	Encina Hub	230.00	230.00	1S		1.44	2
32	Encina Hub	San Luis Rey	230.00	230.00	3		5.87	2
33	Encina Hub		230.00	230.00	1S,3		0.73	2
34			230.00	230.00	1S		0.06	2
35			230.00	230.00	3		0.90	2
36					TOTAL	1,700.17	412.50	434

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1			230.00	230.00	3		5.96	2
2		Palomar	230.00	230.00	1S		0.80	2
3	Encina		230.00	230.00	1S		1.44	2
4			230.00	230.00	3		1.00	1
5			230.00	230.00	3		3.43	2
6			230.00	230.00	1S		10.34	2
7			230.00	230.00	1S		2.00	2
8		Penasquitos	230.00	230.00	1S	0.10		1
9	Penasquitos		230.00	230.00	1S	11.05		1
10		Old Town	230.00	230.00	1S	0.47		1
11	Palomar		230.00	230.00	1S		0.16	1
12		Escondido	230.00	230.00	1S		0.22	1
13	Palomar Generator		230.00	230.00	1S	0.16	0.16	2
14		Escondido	230.00	230.00	1S	0.21	0.22	2
15	East County	ECO GEN 1	230.00	230.00	1S	0.15	0.15	2
16	Miguel		230.00	230.00	3	23.91		2
17			230.00	230.00	3	3.42		1
18		Sycamore Canyon	230.00	230.00	1S	0.56		1
19	Miguel		230.00	230.00	3		23.91	2
20	Miguel		230.00	230.00	1S		1.59	2
21			230.00	230.00	3	1.97		1
22		Mission	230.00	230.00	1S	6.70		1
23	Miguel		230.00	230.00	3	7.52		1
24			230.00	230.00	1S	14.78		1
25		Mission	230.00	230.00	3	9.11		1
26			230.00	230.00	3	0.45		1
27			230.00	230.00	1S	1.59		1
28	Old Town	Mission	230.00	230.00	1S	3.86		2
29	Old Town	Mission	230.00	230.00	1S		3.85	2
30	Silvergate		230.00	230.00	4	0.69		1
31			230.00	230.00	4	0.31		1
32			230.00	230.00	4	5.04		1
33			230.00	230.00	4	0.26		1
34		Old Town	230.00	230.00	4	0.99		1
35	Silvergate		230.00	230.00	4	0.69		1
36					TOTAL	1,700.17	412.50	434

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1			230.00	230.00	4	0.31		1
2			230.00	230.00	4	5.04		1
3			230.00	230.00	4	0.26		1
4		Old Town	230.00	230.00	4	0.99		1
5	Escondido		230.00	230.00	1S	5.02		1
6		Talega	230.00	230.00	3	46.03		1
7	Otay Mesa		230.00	230.00	1S	0.10		1
8		Tijuana	230.00	230.00	3	1.61		1
9	Otay Mesa	Miguel	230.00	230.00	3, 1S		8.92	2
10	Miguel		230.00	230.00	1S		24.61	2
11			230.00	230.00	3		0.67	2
12		Sycamore	230.00	230.00	3		3.62	2
13	Otay Mesa	Miguel	230.00	230.00	3, 1S		8.92	2
14	Miguel	Bay Blvd.	230.00	230.00	1S	9.59		2
15	Bay Blvd.		230.00	230.00	4	2.26		1
16			230.00	230.00	4	0.76		1
17			230.00	230.00	4	0.03		1
18			230.00	230.00	3		3.85	1
19		Silver Gate	230.00	230.00	4	0.40		1
20	Imperial Valley		230.00	230.00	1S	0.04		1
21		IV Gen 3	230.00	230.00	1S	1.36		1
22	Imperial Valley		230.00	230.00	2W	0.82		1
23		La Rosita	230.00	230.00	3	4.64		1
24	Palomar		230.00	230.00	1S		0.80	1
25			230.00	230.00	3		5.96	2
26			230.00	230.00	3	10.12		1
27			230.00	230.00	1S	4.75		1
28			230.00	230.00	3	1.55		1
29		Sycamore Canyon	230.00	230.00	1S	0.17		1
30	San Onofre		230.00	230.00	2S		0.47	2
31	San Onofre	Talega	230.00	230.00	3		6.43	1
32	Penasquitos		230.00	230.00	1S		10.04	2
33		Encina	230.00	230.00	3		8.09	2
34	Sycamore Canyon	Suncrest	230.00	230.00	3	21.77		2
35	Sycamore Canyon	Suncrest	230.00	230.00	3	21.77		2
36					TOTAL	1,700.17	412.50	434

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.
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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Imperial Valley	Drew Switchyard	230.00	230.00	3, 1S	5.33		2
2	Drew Switchyard		230.00	230.00	1S	1.10		1
3		DW Gen 1	230.00	230.00	1S	0.12		1
4	Drew Switchyard	DW Gen 3	230.00	230.00	1S	1.39		1
5	Pico Pico Generator	Otay Mesa Sy	230.00	230.00	1S	0.04		1
6	Total 230kV Pole Line Miles					324.92	200.46	143
7	Encina		138.00	230.00	1S	0.05		2
8		Cannon	138.00	230.00	1S	0.08		2
9	Encina		138.00	138.00	1S	0.63		2
10			138.00	138.00	3	0.70		2
11			138.00	138.00	2W	19.58		1
12			138.00	138.00	4	0.60		1
13		Penasquitos	138.00	138.00	3	1.64		1
14	Palomar		138.00	138.00	1S	0.23		1
15			138.00	138.00	4	0.71		1
16		Batiquitos	138.00	138.00	1S		1.81	2
17	Encina		138.00	138.00	1S	0.02		1
18			138.00	138.00	1S		2.00	2
19			138.00	138.00	3		0.01	2
20		Palomar	138.00	138.00	1S		1.05	2
21	Telegraph Canyon	Proctor Valley	138.00	230.00	1S	2.60		2
22	Friars		138.00	138.00	4	0.16		1
23			138.00	230.00	1S	1.82		2
24		Doublet Tap	138.00	230.00	3		10.22	2
25	Doublet Tap	Doublet Substation	138.00	138.00	1S, 1W	1.81		2
26	Doublet Tap	Penasquitos	138.00	138.00	3		0.70	2
27	Chicarita		138.00	138.00	3, 1S, 1W		10.89	1
28			138.00	138.00	3, 1S		0.96	2
29		Shadowridge	138.00	138.00	1S		3.74	2
30			138.00	138.00	1W, 1S	0.41		1
31		NC Metering	138.00	138.00	1W	0.39		1
32	Telegraph Canyon		138.00	138.00	3	0.05		1
33			138.00	138.00	3		6.70	2
34			138.00	138.00	4	2.44		1
35			138.00	138.00	3		6.43	1
36					TOTAL	1,700.17	412.50	434

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1			138.00	138.00	3		6.43	1
2			138.00	138.00	3, 1W	0.08		3
3			138.00	138.00	1W, 1S		1.23	3
4		Grant Hill	138.00	138.00	4	0.86		1
5	Capistrano		138.00	138.00	3, 1S, W	0.10	1.55	1
6		Pico	138.00	138.00	3, 1S		4.82	1
7	Santee		138.00	138.00	1W, 1S	2.35		1
8			138.00	138.00	1S	4.24		2
9			138.00	138.00	3, 1S	0.34		1
10		Los Coches	138.00	138.00	3	0.04		1
11	Sycamore		138.00	138.00	1W	5.71		1
12		Chicarita	138.00	138.00	4	0.06		1
13	Sycamore		138.00	138.00	1S		6.63	2
14		Santee	138.00	138.00	1W	1.56		1
15	Mission		138.00	138.00	2W		0.20	1
16			138.00	138.00	3, 1S		1.69	2
17		(Tower Z874970)	138.00	138.00	3	1.69	8.00	2
18	(Tower Z874970)	Carlton Hills	138.00	138.00	3, 1S		1.44	2
19	Telegraph Canyon	Miguel 60 Tap	138.00	138.00	3		3.11	2
20	Miguel 60 Tap		138.00	138.00	3		0.69	2
21		Miguel	138.00	138.00	3		0.02	2
22	Miguel 60 Tap	Los Coches	138.00	138.00	3		12.43	2
23	North City Mtr Tap	Meadowlark Tap	138.00	138.00	3		7.40	2
24	Batiquitos	Meadowlark Tap	138.00	138.00	1S	2.58		2
25	Chicarita	Meadowlark Tap	138.00	138.00	2W	12.04		1
26	Shadowridge	Meadowlark Tap	138.00	138.00	3, 1W	3.99		2
27	Miguel		138.00	138.00	3	1.29		2
28		Proctor Valley	138.00	138.00	1W	0.05		1
29	Friars		138.00	138.00	4	0.10		
30		Mission	138.00	230.00	1S, 3	1.22		2
31	Sycamore		138.00	138.00	1S	4.06	4.06	2
32		Carlton Hills	138.00	138.00	1S, 3	1.81	1.44	2
33	Margarita		138.00	138.00	3	1.22		2
34			138.00	230.00	1S	0.78		1
35		Trabuco	138.00	138.00	4	3.32		1
36					TOTAL	1,700.17	412.50	434

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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.
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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	Talega	Rancho Mission Viejo	138.00	138.00	1S, 1W	7.74		1
2	Trabuco		138.00	138.00	1W	3.80		1
3			138.00	138.00	1S, 3		6.50	2
4			138.00	138.00	4	0.33		1
5		Pico	138.00	138.00	3	3.49		2
6	Trabuco		138.00	138.00	1W	3.70		1
7			138.00	138.00	1W	0.01		1
8		Capistrano	138.00	138.00	1W	0.02		1
9	San Mateo	San Mateo Tap	138.00	138.00	1W	0.66		1
10	San Mateo Tap	Z203020	138.00	138.00	3, 1W		7.08	2
11	Z203020	Z203021	138.00	138.00	4	0.33		1
12	Z203021	Z196606	138.00	138.00	1S	0.25		1
13	Z196606	Z248108	138.00	138.00	1W, 2W, 1S, 3	6.74		1
14	Z248108	Laguna Niguel	138.00	138.00	4	1.85		1
15	Talega Tap	Talega	138.00	138.00	1W	0.36		1
16	Pico		138.00	138.00	3, 1S		0.68	2
17		Talega	138.00	138.00	1W, S	0.11	0.41	1
18	Capistrano		138.00	138.00	1W	0.01		1
19			138.00	138.00	1W, 1S	1.38		1
20		Laguna NIguel	138.00	138.00	4	1.82		
21	Rancho Mission Viejo	Margarita	138.00	138.00	1W, S	1.30		1
22	Mission		138.00	138.00	1S, W	2.94		2
23		Grant HIll	138.00	138.00	4	2.84		1
24	Encina	Encina Hub	138.00	138.00	1S	1.28	1.28	1
25	Encina Hub	Shadowridge	138.00	138.00	2W	6.72		1
26	East County	Boulevard East	138.00	138.00	1S	6.97		1
27	East County	Boulevard East	138.00	138.00	4	5.60		1
28	East County	Boulevard East	138.00	138.00	4	1.12		1
29	East County	Boulevard East	138.00	138.00	4	0.18		1
30	Pico		138.00	138.00	3, 1S	0.90		2
31		Talega	138.00	138.00	1W	0.36		1
32			138.00	138.00	3		2.85	2
33		San Mateo	138.00	138.00	1W	0.60		1
34	Encina		138.00	230.00	1S		0.05	2
35		Cannon	138.00	230.00	1S		0.08	2
36					TOTAL	1,700.17	412.50	434

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	13832	De-Energized	138.00	138.00	3, 1S, 1W	3.36		1
2	13832	De-Energized	138.00	138.00	3, 1S, 1W	3.21		1
3	13811	De-Energized	138.00	138.00	1S	1.07		1
4	13811	De-Energized	138.00	138.00	3	5.69		1
5	13822	De-Energized	138.00	138.00	2W	0.06		1
6	Cannon	Encina Hub	138.00	138.00	1S		1.27	2
7	Encina Hub	Calavera Tap	138.00	138.00	2W	0.39		1
8	Encina Hub	Calavera Tap	138.00	138.00	2W	2.94		1
9	Calavera Tap	San Luis Rey	138.00	138.00	2W	3.89		1
10	Bay Blvd.		138.00	138.00	3		2.95	2
11		Telegraph Canyon					3.75	2
12	Total 138 kV Pole Line Mile				0.00	167.43	132.55	157
13	69kV Lines				1W	712.89	25.40	125
14					2W	7.11	1.38	
15					1S	37.12	1.50	
16					3	20.00	50.61	
17					4	62.10	0.60	
18	Total 69kV Pole Line Miles					839.22	79.49	125
19								
20								
21	EXPENSES, EXCEPT ISO							
22	Cost of Line							
23	ISO CHARGES							
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,700.17	412.50	434

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	
2-2156 ACSR								1
2-2156 ACSR								2
2-2156 ACSR								3
2-2156 ACSR								4
2-2156 ACSR								5
3-1033.5 ACSR								6
2-2156 ACSR								7
3-1033.5 ACSR								8
2-1590 ACSR								9
								10
1033.5 ACSR								11
1033.5 ACSR								12
1033.5 ACSR								13
1033.5 ACSR								14
2-1033.5 ACSR								15
1033.5 ACSR								16
1033.5 ACSR								17
2-1033.5 ACSR								18
2-1109 ACAR								19
1033.5 ACSR								20
1033.5 ACSR								21
1033.5 ACSR								22
1033.5 ACSR								23
2-1033.5 ACSR								24
1033.5 ACSR								25
2-1033.5 ACSR								26
2-1033.5 ACSR								27
1033.5 ACSR								28
1033.5 ACSR								29
1033.5 ACSR								30
2-1109 ACAR								31
2-1033.5 ACSR								32
2-1109 ACAR								33
2-1109 ACAR								34
2-1109 ACAR								35
	185,148,691	2,953,892,494	3,139,041,185	14,860,154	18,950,023	2,507,242	36,317,419	36

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TRANSMISSION LINE STATISTICS (Continued)

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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.
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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)	
2-1109 ACAR								1
2-900 ACSS								2
2-1109 ACAR								3
2-1109 ACAR								4
2-1109 ACAR								5
2-1109 ACAR								6
2-1109 ACAR								7
2-1033.5 ACSR								8
2-1109 ACAR								9
2-1033.5 ACSR								10
900 ACSS								11
605 ACSS								12
900 ACSS								13
605 ACSS								14
1113 ACSS								15
2-1033.5 ACSR								16
2-1109 ACAR								17
2-1033.5 ACSR								18
2-1033.5 ACSR								19
2-1033.5 ACSR								20
2-1109 ACAR								21
2-1109 ACAR								22
1109 ACAR								23
636 ACSS								24
605 ACSS								25
1033.5 ACSR								26
1033.5 ACSR								27
1109 ACAR								28
1109 ACAR								29
1-3500 KCMIL CU								30
1-2500 KCMIL CU								31
1-3500 KCMIL CU								32
1-2500 KCMIL CU								33
1-3500 KCMIL CU								34
1-3500 KCMIL CU								35
	185,148,691	2,953,892,494	3,139,041,185	14,860,154	18,950,023	2,507,242	36,317,419	36

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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.
1-2500 KCMIL CU								1
1-3500 KCMIL CU								2
1-2500 KCMIL CU								3
1-3500 KCMIL CU								4
1033.5 ACSR								5
1033.5 ACSR								6
2-900 ACSS								7
2-1033.5 ACSR								8
2-900 ACSS								9
2-1033.5 ACSR								10
2-605 ACSR								11
2-1109 ACAR								12
2-900 ACSS								13
2-900 ACSS								14
2-3500 KCMIL CU								15
2-4000 KCMIL								16
2-3500 KCMIL CU								17
1-900 ACSS								18
2-3500 KCMIL CU								19
2-1033.5 ACSS/AW								20
2-1033.5 ACSS/TW								21
1033.5 ACSR								22
1033.5 ACSR								23
2-900 ACSS								24
2-1109 ACAR								25
2-1109 ACAR								26
2-1109 ACAR								27
2-1109 ACAR								28
2-1033.5 ACSR								29
2-1033.5 ACSR								30
1033.5 ACSR								31
1109 ACAR								32
1033.5 ACSR								33
900 ACSS								34
900 ACSS								35
	185,148,691	2,953,892,494	3,139,041,185	14,860,154	18,950,023	2,507,242	36,317,419	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)	
2-900 ACSS								1
2-900 ACSS								2
2-636 ACSS								3
900 ACSS								4
1-1272 ACSS								5
								6
2-1033.5 ACSR								7
2-1109 ACAR								8
2-1109 ACAR								9
2-1109 ACAR								10
2-636 ACSR								11
1033.5 ACSR								12
2-636 ACSR								13
2-1109 ACAR								14
2-1109 ACAR								15
2-1033.5 ACSR								16
2-1109 ACAR								17
2-1109 ACAR								18
2-1109 ACAR								19
2-1033 ACSR								20
2-1109 ACAR								21
2-2500 KCMIL CU								22
400 MCM CU								23
636 ACSR/AW								24
336.4 ACSR/AW								25
636 ACSR/AW								26
636 ACSR								27
2-1033.5 ACSR								28
2-1033.5 ACSR								29
250MCM CU								30
336.4 ACSR								31
1-1033.5 ACSR								32
2-636 ACSR								33
2500 KCMIL CU								34
2-400 MCM CU								35
	185,148,691	2,953,892,494	3,139,041,185	14,860,154	18,950,023	2,507,242	36,317,419	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)
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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)	
1-1033.5 ACSR								1
2-1033.5 ACSR								2
2-636 ACSR								3
2500 KCMIL CU								4
1033.5 ACSR								5
636 ACSR								6
1-1033.5 ACSR								7
605 ACSS								8
2-336.4 ACSR								9
1-750 MCM CU								10
636 ACSR								11
1750 KCMIL								12
900 ACSS/AW								13
636 ACSS								14
1-336.4 ACSR								15
2-336.4 ACSR								16
4-336.4 ACSR								17
900 ACSS/AW								18
2-636 ACSR								19
2-900 ACSS								20
636 ACSR								21
2-636 ACSS								22
1033.5 ACSR								23
636 ACSR								24
250 MCM CU								25
250 MCM CU								26
1033.5 ACSR								27
2-636 ACSR								28
1-1750 KCMIL AL								29
1-900 ACSS/AW								30
1-900 ACSS/AW								31
1-900 ACSS/AW								32
1033.5 ACSR								33
1750 AL UG								34
1033.5 ACSR								35
	185,148,691	2,953,892,494	3,139,041,185	14,860,154	18,950,023	2,507,242	36,317,419	36

Name of Respondent San Diego Gas & Electric 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 (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)
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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.
1033.5 ACSR								1
1033.5 ACSR								2
1033.5 ACSR								3
1750 MCM CU								4
1033.5 ACSR								5
636 ACSR								6
636 ACSR								7
336.4 ACSR								8
1033.5 ACSR/AW								9
336.4 ACSR/AW								10
1750 KCMIL AL								11
1033.5 ACSR/AW								12
336.4 ACSR/AW								13
1750 KCMIL AL								14
1033.5 ACSR/AW								15
900 ACSS								16
1033.5 ACSR								17
636 ACSR/AW								18
336.4 ACSR/AW								19
1750 KCMIL AL								20
1033.5 ACSR								21
2-636 ACSR								22
2500 MCM CU								23
2-1109 ACAR								24
900 ACSS								25
900 ACSS								26
2-2500 KCMIL CU								27
2-3000 KCMIL CU								28
2-5000 KCMIL CU								29
1033.5 ACSR								30
1033.5 ACSR								31
336.4 ACSR								32
1033.5 ACSR								33
2-1033.5 ACSR								34
2-1109 ACAR								35
	185,148,691	2,953,892,494	3,139,041,185	14,860,154	18,950,023	2,507,242	36,317,419	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)
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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.
336.4 ACSR								1
250 MCM CU								2
900 ACSS/AW								3
250 MCM CU								4
1109 ACAR								5
2-1109 ACAR								6
1033.5 ACSR								7
636 ACSS								8
1033.5ACSR								9
636 ACSR/AW								10
2-400 MCM CU								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
				10,289,077	18,950,023	2,507,242	31,746,342	21
	185,148,691	2,953,892,494	3,139,041,185					22
				4,571,077			4,571,077	23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	185,148,691	2,953,892,494	3,139,041,185	14,860,154	18,950,023	2,507,242	36,317,419	36

Schedule Page: 422 Line No.: 2 Column: f

San Diego Gas & Electric owns 85.64% and Imperial Irrigation District owns 14.36%.

Schedule Page: 422 Line No.: 3 Column: f

San Diego Gas & Electric owns 85.64% and Imperial Irrigation District owns 14.36%.

Schedule Page: 422 Line No.: 4 Column: f

Line has two sections: Palo Verde to North Gila, and North Gila to the Colorado River. SDG&E owns 76.22% and 85.64%, respectively, while Arizona Public Service owns 23.78% and 14.36%, respectively.

Schedule Page: 422.6 Line No.: 22 Column: j

Costs available in total only.

Schedule Page: 422.6 Line No.: 22 Column: k

Costs available in total only.

Schedule Page: 422.6 Line No.: 22 Column: l

Costs available in total only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OVERHEAD						
2							
3	Montgomery	Bay Blvd	0.54	1S	9.00	2	2
4							
5	Montgomery	Bay Blvd	0.50	1S	9.00	1	1
6							
7	Sweetwater	Bay Blvd	0.70	1W	9.00	1	1
8							
9	Otay	Bay Blvd	0.03	1S	9.00	1	1
10							
11	Otay	Bay Blvd	0.04	1W	9.00	1	1
12							
13	Imperial Beach	Bay Blvd	0.04	1W	9.00	1	1
14							
15	Elliot	Los Coches	0.53	1S	6.00	1	1
16							
17	Mission	Carlton Hills	0.20	1S	6.00	1	2
18							
19	Miguel	Mission	0.54	1S	6.00	2	2
20							
21	Miguel	Mission	0.54	1S	6.00	2	2
22							
23	UNDERGROUND						
24							
25	Grant Hill	Telegraph Canyon	0.84	4		1	2
26							
27	Montgomery	Bay Blvd	0.07	4		1	1
28							
29	Montgomery	Bay Blvd	0.08	4		1	1
30							
31	Sweetwater	Bay Blvd	0.15	4		1	1
32							
33	Otay	Bay Blvd	0.12	4		1	1
34							
35	Otay	Bay Blvd	0.04	4		1	1
36							
37	Imperial Beach	Bay Blvd	0.04	4		1	1
38							
39	El Cajon	Los Coches	0.07	4		1	1
40							
41	El Cajon	Los Coches	0.06	4		1	1
42							
43	Los Coches	Loveland	0.10	4		1	1
44	TOTAL		5.41		78.00	25	27

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		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							
2	Rancho Carmel	Poway	0.08	4		1	1
3							
4	Rancho Carmel	Poway	0.10	4		1	1
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
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34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		5.41		78.00	25	27

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			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
636	ACSR/AW	6	69		491,918	306,531		798,449	3
									4
2-636	ACSS/AW	6	69		391,064	224,601		615,665	5
									6
2-636	ACSR/AW	6	69		291,624	1,631,214		1,922,838	7
									8
2-636	ACSS/AW	6	69		262,460	99,758		362,218	9
									10
1033.5	ACSR/AW	6	69		206,084	256,136		462,220	11
									12
1033.5	ACSR/AW	6	69		171,242	113,766		285,008	13
									14
1-900	ACSS/AW	6	69		2,480,717	1,443,342		3,924,059	15
									16
1-900	ACSS/AW	9	138		940,962	547,475		1,488,437	17
									18
2-1033.5	ACRS/AW	16	230		2,566,259	1,493,113		4,059,372	19
									20
1-1033.5	ACRS/AW	16	230		2,566,259	1,493,113		4,059,372	21
									22
									23
									24
1-2500	KCMIL	8"	138			6,347,317		6,347,317	25
									26
1-3000	KCMILCU	8"	69			1,010,073		1,010,073	27
									28
2-3000	KCMILCU	8"	69			1,049,052		1,049,052	29
									30
2-3000	KCMILCU	8"	69			1,595,000		1,595,000	31
									32
1-1750	KCMILCU	8"	69			1,307,981		1,307,981	33
									34
1-1750	KCMILCU	8"	69			775,734		775,734	35
									36
1-1750	KCMILCU	8"	69			908,216		908,216	37
									38
1-3000	KCMILCU	8"	69			369,105		369,105	39
									40
1-3000	KCMILCU	8"	69			580,526		580,526	41
									42
1-3000	KCMILCU	8"	69			531,151		531,151	43
					10,368,589	23,588,054		33,956,643	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Line No.
									1
3000	KCMILCU	8"	69			662,134		662,134	2
									3
3000	KCMILCU	8"	69			842,716		842,716	4
									5
									6
									7
									8
									9
									10
									11
									12
									13
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									40
									41
									42
									43
					10,368,589	23,588,054		33,956,643	44

Name of Respondent San Diego Gas & Electric 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

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	ALPINE, Alpine	Dist. Unattended	69.00	12.00	
2	AMHERST, San Diego	Dist. Unattended	12.00	4.00	
3	ARTESIAN, San Diego	Dist. Unattended	69.00	12.00	
4	ASH, Escondido	Dist. Unattended	69.00	12.00	
5	AVOCADO, Fallbrook	Dist. Unattended	69.00	12.00	
6	B, San Diego	Dist. Unattended	69.00	12.00	
7	BARRETT, Barrett	Dist. Unattended	69.00	12.00	
8	BASILONE, San Clemente	Dist. Unattended	69.00	12.00	
9	BATIQUITOS, Encinitas	Dist. Unattended	138.00	12.00	
10	BERNARDO, Rancho Bernardo	Dist. Unattended	69.00	12.00	
11	BORDER, San Diego	Dist. Unattended	69.00	12.00	
12	BORREGO, Borrego Springs	Dist. Unattended	69.00	12.00	
13	BOSTONIA, El Cajon	Dist. Unattended	12.00	4.00	
14	BOULDER CREEK, Santa Ysabel	Dist. Unattended	69.00	12.00	
15	BOULEVARD EAST, Boulevard	Dist. Unattended	138.00	12.00	
16	CABRILLO, San Diego	Dist. Unattended	69.00	12.00	
17	CALAVO GARDENS, El Cajon	Dist. Unattended	12.00	4.00	
18	CAMERON, Campo	Dist. Unattended	69.00	12.00	
19	CANNON, Carlsbad	Dist. Unattended	138.00	12.00	
20	CAPISTRANO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
21	CARLTON HILLS, Santee	Dist. Unattended	138.00	12.00	
22	CENTRAL, San Diego	Dist. Unattended	12.00	4.00	
23	CHICARITA, San Diego	Dist. Unattended	138.00	12.00	
24	CHOLLAS, Lemon Grove	Dist. Unattended	69.00	12.00	
25	CHULA VISTA, San Diego	Dist. Unattended	12.00	4.00	
26	CLAIREMONT, San Diego	Dist. Unattended	69.00	12.00	
27	CORONADO, Coronado	Dist. Unattended	69.00	12.00	
28	CREELMAN, Ramona	Dist. Unattended	69.00	12.00	
29	CRESTWOOD, Campo	Dist. Unattended	69.00	12.00	
30	CRISTIANITOS, Mission Viejo	Dist. Unattended	69.00	12.00	
31	DEL MAR, Del Mar	Dist. Unattended	69.00	12.00	
32	DESCANSO, Descanso	Dist. Unattended	69.00	12.00	
33	DIVISION, San Diego	Dist. Unattended	69.00	12.00	
34	DUNHILL, San Diego	Dist. Unattended	69.00	4.00	
35	EAST OCEANSIDE, Oceanside	Dist. Unattended	12.00	4.00	
36	EASTGATE, San Diego	Dist. Unattended	69.00	12.00	
37	EL CAJON, El Cajon	Dist. Unattended	69.00	12.00	
38	ELLIOTT, San Diego	Dist. Unattended	69.00	12.00	
39	ENCANTO, San Diego	Dist. Unattended	12.00	4.00	
40	ENCINITAS, Encinitas	Dist. Unattended	69.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ENCINITAS, Encinitas	Dist. Unattended	12.00	4.00	
2	ESCO, Escondido	Dist. Unattended	69.00	12.00	
3	ESCO, Escondido	Dist. Unattended	12.00	4.00	
4	ESCONDIDO, Escondido	Dist. Unattended	69.00	12.00	
5	F, San Diego	Dist. Unattended	69.00	12.00	
6	FELICITA, Escondido	Dist. Unattended	69.00	12.00	
7	FENTON, San Diego	Dist. Unattended	69.00	12.00	
8	FRIARS, San Diego	Dist. Unattended	138.00	12.00	
9	GARFIELD, El Cajon	Dist. Unattended	69.00	12.00	
10	GENESEE, San Diego	Dist. Unattended	69.00	12.00	
11	GLENCLIFF-GC	Dist. Unattended	69.00	12.00	
12	GRANITE, El Cajon	Dist. Unattended	69.00	12.00	
13	GRANT HILL, San Diego	Dist. Unattended	138.00	12.00	
14	HILLTOP, San Diego	Dist. Unattended	12.00	4.00	
15	IMPERIAL BEACH, Imperial Beach	Dist. Unattended	69.00	12.00	
16	IMPERIAL BEACH, Imperial Beach	Dist. Unattended	12.00	4.00	
17	JAMACHA, Jamacha	Dist. Unattended	69.00	12.00	
18	JAPANESE MESA, San Clemente	Dist. Unattended	69.00	12.00	
19	KEARNY, San Diego	Dist. Unattended	69.00	12.00	
20	KETTNER, San Diego	Dist. Unattended	69.00	12.00	
21	KYOCERA, San Diego	Dist. Unattended	69.00	12.00	
22	LA JOLLA, La Jolla	Dist. Unattended	69.00	12.00	
23	LAGUNA NIGUEL, Laguna Niguel	Dist. Unattended	138.00	12.00	
24	LAS PULGAS, Oceanside	Dist. Unattended	69.00	12.00	
25	LILAC, Valley Center	Dist. Unattended	69.00	12.00	
26	LINCOLN ACRES, National City	Dist. Unattended	12.00	4.00	
27	LOS COCHES, Lakeside	Dist. Unattended	69.00	12.00	
28	LOVELAND, Alpine	Dist. Unattended	69.00	12.00	
29	MARGARITA, Mission Viejo	Dist. Unattended	138.00	12.00	
30	MELROSE, Vista	Dist. Unattended	69.00	12.00	
31	MESA HEIGHTS, San Diego	Dist. Unattended	69.00	12.00	
32	MESA RIM, San Diego	Dist. Unattended	69.00	12.00	
33	MIRAMAR, San Diego	Dist. Unattended	69.00	12.00	
34	MIRA SORRENTO, San Diego	Dist. Unattended	69.00	12.00	
35	MISSION, San Diego	Dist. Unattended	69.00	12.00	
36	MONSERATE, Fallbrook	Dist. Unattended	69.00	12.00	
37	MONTGOMERY, Chula Vista	Dist. Unattended	69.00	12.00	
38	MORRO HILL, Oceanside	Dist. Unattended	69.00	12.00	
39	MURRAY, La Mesa	Dist. Unattended	69.00	12.00	
40	NATIONAL CITY, National City	Dist. Unattended	69.00	4.00	12.00

Name of Respondent San Diego Gas & Electric 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

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NAVAL STATION Switchyard, San Diego-NSM	Dist. Unattended	69.00		
2	NORTH CITY WEST, San Diego	Dist. Unattended	69.00	12.00	
3	NORTH VISTA,Vista	Dist. Unattended	12.00	4.00	
4	OCEANSIDE, Oceanside	Dist. Unattended	69.00	12.00	
5	OLD TOWN, San Diego	Dist. Unattended	69.00	12.00	
6	OLIVENHAIN, Escondido	Dist. Unattended	69.00	12.00	
7	OTAY LAKES, Chula Vista	Dist. Unattended	69.00	12.00	
8	OTAY, Chula Vista	Dist. Unattended	69.00	12.00	
9	PACIFIC BEACH, San Diego	Dist. Unattended	69.00	12.00	
10	PALA, San Diego County	Dist. Unattended	69.00	12.00	
11	PALOMAR AIRPORT, Carlsbad	Dist. Unattended	138.00	12.00	
12	PARADISE, San Diego	Dist. Unattended	69.00	12.00	
13	PENDLETON, Oceanside	Dist. Unattended	69.00	12.00	
14	PICO, San Clemente	Dist. Unattended	138.00	12.00	
15	POINT LOMA SEWAGE, San Diego	Dist. Unattended	12.00	4.00	
16	POINT LOMA, San Diego	Dist. Unattended	69.00	12.00	
17	POMERADO, San Diego	Dist. Unattended	69.00	12.00	
18	POWAY, Poway	Dist. Unattended	69.00	12.00	
19	PROCTOR VALLEY, Bonita	Dist. Unattended	138.00	12.00	
20	RAMONA, Ramona	Dist. Unattended	12.00	4.00	
21	RANCHO CARMEL, San Diego	Dist. Unattended	69.00	12.00	
22	RANCHO MISSION VIEJO, Rancho Mission Viejo	Dist. Unattended	138.00	12.00	
23	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	12.00	
24	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	4.00	
25	RINCON, Rincon	Dist. Unattended	69.00	12.00	
26	ROLANDO, San Diego	Dist. Unattended	12.00	4.00	
27	ROSE CANYON, San Diego	Dist. Unattended	69.00	12.00	
28	ROSEVILLE, San Diego	Dist. Unattended	12.00	4.00	
29	SAMPSON, San Diego	Dist. Unattended	69.00	12.00	
30	SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
31	SAN LUIS REY, Oceanside	Dist. Unattended	69.00	12.00	
32	SAN MARCOS, San Marcos	Dist. Unattended	69.00	12.00	
33	SAN MATEO, San Clemente	Dist. Unattended	138.00	12.00	
34	SAN YSIDRO, San Ysidro	Dist. Unattended	69.00	12.00	
35	SANTA YSABEL, Santa Ysabel	Dist. Unattended	69.00	12.00	
36	SANTEE, Santee	Dist. Unattended	138.00	12.00	
37	SCRIPPS, San Diego	Dist. Unattended	69.00	12.00	
38	SEWAGE PUMP STA (3), San Diego	Dist. Unattended	12.00	4.00	
39	SHADOWRIDGE, Vista	Dist. Unattended	138.00	12.00	
40	SHORECLIFFS, San Clemente	Dist. Unattended	12.00	4.00	

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San Diego Gas & Electric 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	SOUTH SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
2	SPRING VALLEY, Spring Valley	Dist. Unattended	69.00	12.00	
3	STREAMVIEW, San Diego	Dist. Unattended	69.00	12.00	
4	STUART, Oceanside	Dist. Unattended	69.00	12.00	
5	SUNNYSIDE, San Diego	Dist. Unattended	69.00	12.00	
6	SWEETWATER, National City	Dist. Unattended	69.00	12.00	
7	TELEGRAPH CANYON, Chula Vista	Dist. Unattended	138.00	12.00	
8	TORREY PINES, San Diego	Dist. Unattended	69.00	12.00	
9	TRABUCO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
10	UCM Switchyard, San Diego	Dist. Unattended	69.00		
11	URBAN, San Diego	Dist. Unattended	69.00	12.00	
12	VALLEY CENTER, Valley Center	Dist. Unattended	69.00	12.00	
13	VISTA, Vista	Dist. Unattended	12.00	4.00	
14	WARNERS, Warner Springs	Dist. Unattended	69.00	12.00	
15	WARREN CANYON, Poway	Dist. Unattended	69.00	12.00	
16	WARREN CANYON, Poway	Dist. Unattended	69.00	4.00	
17	WITHERBY, San Diego	Dist. Unattended	12.00	4.00	
18	BAY BOULEVARD, Chula Vista	Trans. Unattended	230.00	69.00	
19	DOUBLETT Switchyard, San Diego	Trans. Unattended	138.00	69.00	
20	EAST COUNTY, Boulevard	Trans. Unattended	500.00	230.00	12.00
21	EAST COUNTY, Boulevard	Trans. Unattended	230.00	138.00	
22	ENCINA Switchyard, Carlsbad	Trans. Unattended	138.00		
23	ENCINA, Carlsbad	Trans. Unattended	230.00	138.00	
24	ESCONDIDO, Escondido	Trans. Unattended	230.00	69.00	
25	GOAL LINE, Escondido	Trans. Unattended	69.00		
26	IMPERIAL VALLEY, El Centro	Trans. Unattended	500.00	230.00	12.00
27	LOS COCHES, Lakeside	Trans. Unattended	138.00	69.00	
28	MIGUEL, Bonita	Trans. Unattended	230.00	69.00	
29	MIGUEL, Bonita	Trans. Unattended	230.00	138.00	
30	MIGUEL, Bonita	Trans. Unattended	500.00	230.00	12.00
31	MIRAMAR GT, San Diego	Trans. Unattended	12.00	69.00	
32	MISSION, San Diego	Trans. Unattended	138.00	69.00	
33	MISSION, San Diego	Trans. Unattended	230.00	69.00	
34	MISSION, San Diego	Trans. Unattended	230.00	138.00	
35	NARROWS, Borrego Springs	Trans. Unattended	88.00	69.00	12.00
36	OCOTILLO Switchyard, Ocotillo	Trans. Unattended	500.00		
37	OLD TOWN, San Diego	Trans. Unattended	230.00	69.00	
38	OTAY MESA Switchyard, Chula Vista	Trans. Unattended	230.00		
39	PENASQUITOS, San Diego	Trans. Unattended	138.00	69.00	
40	PENASQUITOS, San Diego	Trans. Unattended	230.00	138.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PENASQUITOS, San Diego	Trans. Unattended	230.00	69.00	
2	SAN LUIS REY, Oceanside	Trans. Unattended	230.00	69.00	
3	SILVERGATE, San Diego	Trans. Unattended	230.00	69.00	
4	SOUTH BAY, Chula Vista	Trans. Unattended	138.00	69.00	
5	SUNCREST, Japatul	Trans. Unattended	500.00	230.00	12.00
6	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	69.00	
7	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	138.00	
8	TALEGA, San Clemente	Trans. Unattended	138.00	69.00	
9	TALEGA, San Clemente	Trans. Unattended	230.00	138.00	
10	WABASH Switchyard, San Diego	Trans. Unattended	69.00		
11					
12					
13					
14					
15					
16					
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18					
19					
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21					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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.
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.
56	2					1
6	1					2
56	2					3
84	3	1				4
41	2					5
112	4					6
13	1					7
28	1					8
56	2	1				9
140	5					10
56	2					11
26	2					12
10	1					13
2	1					14
28	1					15
56	2					16
7	2					17
6	1					18
112	4					19
56	2					20
56	2					21
6	1					22
84	3					23
56	2	1				24
6	2					25
56	2					26
56	2					27
84	3					28
13	1					29
8	1					30
84	3					31
7	1					32
53	2					33
8	1					34
6	1					35
56	2					36
112	4					37
84	3					38
1	4					39
56	2					40

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San Diego Gas & Electric 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.
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.
6	1					1
56	2					2
4	1					3
112	4					4
84	3					5
84	3					6
8	1					7
56	2					8
28	1					9
112	4					10
7	1					11
112	4					12
56	2					13
3	1					14
56	2					15
6	1					16
84	3					17
14	2					18
84	3					19
56	2					20
9	1					21
56	2					22
112	4					23
28	1					24
56	2					25
6	1					26
84	3					27
28	1					28
112	4					29
112	4					30
84	3					31
112	4					32
84	3					33
56	2					34
112	4					35
56	2					36
56	2					37
13	1					38
112	4	1				39
14	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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.
						1
56	2					2
3	1					3
56	2					4
84	3	1				5
28	1					6
5	1					7
56	2	1				8
56	2					9
28	1					10
84	3					11
56	2					12
56	2					13
56	2					14
6	1					15
84	2					16
84	3					17
56	2					18
56	2	1				19
6	1					20
84	3					21
56	2					22
41	2					23
6	1					24
25	2					25
13	2					26
56	2					27
6	1					28
112	4					29
3	1					30
112	4					31
112	4					32
45	2					33
56	2					34
12	1					35
56	2					36
84	3					37
30	6	3				38
84	3					39
3	1					40

Name of Respondent San Diego Gas & Electric 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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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)	
3	1					1
56	2					2
56	2					3
8	1					4
28	1					5
56	2					6
112	4					7
112	4					8
112	4					9
						10
84	3					11
28	1					12
10	2					13
28	1					14
8	1					15
7	1					16
6	1					17
448	2					18
						19
1120	1					20
392	1					21
						22
784	2					23
672	3					24
						25
2840	9	2				26
448	2					27
448	2					28
784	2					29
2240	6	1				30
50	1					31
499	5					32
224	1					33
784	2					34
10	3					35
						36
448	2					37
						38
520	3					39
392	1	1				40

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SUBSTATIONS (Continued)

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448	2					1
672	3					2
672	3					3
224	1					4
2240	6	1				5
672	3	1				6
392	1	1				7
140	1	1				8
1102	4		230/12kV	2	10	9
						10
						11
						12
						13
						14
						15
						16
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						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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	Construction Work in Progress	Sempra Energy	107	11,217,726
3	Other Utility Plant	Sempra Energy	118	105,053
4	Other Special Funds	Sempra Energy	128	-5,844,705
5	Cash	Sempra Energy	131	12,883
6	Other Accounts Receivable	Sempra Energy	143	424,836
7	Accounts Receivable from Associated Companies	Sempra Energy	146	-82,611
8	Stores Expense Undistributed	Sempra Energy	163	-142,315
9	Prepayments	Sempra Energy	165	79,814,019
10	Unamortized Debt Expense	Sempra Energy	181	697,136
11	Preliminary Survey and Investigation Charges	Sempra Energy	183	4,645
12	Clearing Accounts	Sempra Energy	184	2,908,423
13	Research, Development, & Demonstration Expenditure	Sempra Energy	188	2,219
14	Accumulated Provision for Injuries and Damages	Sempra Energy	228.2	3
15	Accumulated Miscellaneous Operating Provisions	Sempra Energy	228.4	129
16	Accounts Payable	Sempra Energy	232	-922,875
17	Miscellaneous Current and Accrued Liabilities	Sempra Energy	242	274,875
18	Other Regulatory Liabilities	Sempra Energy	254	12,000,000
19	Expend. for Civic & Political Activities	Sempra Energy	426.4	461,787
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounting & Finance	Sempra Energy	146	1,226,751
22	Depreciation Expense	Sempra Energy	146	634,555
23	Environmental Services	Sempra Energy	146	27,103
24	External Affairs	Sempra Energy	146	216,850
25	Fleet Services	Sempra Energy	146	34,382
26	Human Resources	Sempra Energy	146	11,102,727
27	Information Technology	Sempra Energy	146	2,891,767
28	Real Estate & Facilities	Sempra Energy	146	7,980,986
29	Supply Management	Sempra Energy	146	1,182,643
30	Accounting & Finance	U.S. Gas & Power Natural Gas	146	-4,664
31	Depreciation Expense	U.S. Gas & Power Natural Gas	146	73,118
32	Environmental Services	U.S. Gas & Power Natural Gas	146	851
33	External Affairs	U.S. Gas & Power Natural Gas	146	26,046
34	Human Resources	U.S. Gas & Power Natural Gas	146	-12,267
35	Information Technology	U.S. Gas & Power Natural Gas	146	324,874
36	Real Estate & Facilities	U.S. Gas & Power Natural Gas	146	97,870
37	Supply Management	U.S. Gas & Power Natural Gas	146	336,035
38	Accounting & Finance	U.S. Gas & Power Renewables	146	567
39	Depreciation Expense	U.S. Gas & Power Renewables	146	89,725
40	Engineering / Const. Services	U.S. Gas & Power Renewables	146	43,065
41	Environmental Services	U.S. Gas & Power Renewables	146	436
42	Human Resources	U.S. Gas & Power Renewables	146	72,634
1	**Non-power Goods or Services Provided by Affiliated**			
2	Other Electric Revenues	Sempra Energy	456	331

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric 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)
3	Steam Power Operation Supervision and Engineering	Sempra Energy	500	1,089
4	Miscellaneous Steam Power Expense	Sempra Energy	506	802,770
5	Maintenance and Miscellaneous Steam Plant	Sempra Energy	514	66
6	Operation Supervision and Engineering	Sempra Energy	546	802
7	Miscellaneous Other Power Generation Expenses	Sempra Energy	549	2,075
8	Maintenance and Miscellaneous Other Plant	Sempra Energy	554	767
9	Purchased Power	Sempra Energy	555	-6,000,000
10	System Control and Load Dispatching	Sempra Energy	556	670
11	Other Expenses	Sempra Energy	557	7,221
12	Power Transmission Operation Supervision and Engig	Sempra Energy	560	7,450
13	Load Dispatching	Sempra Energy	561	2,020
14	Station Expenses	Sempra Energy	562	140
15	Miscellaneous Transmission Expenses	Sempra Energy	566	242,637
16	Maintenance Supervision	Sempra Energy	568	3
17	Maintenance of Structures	Sempra Energy	569	9,159
18	Maintenance of Station Equipment	Sempra Energy	570	487
19	Maintenance of Overhead Lines	Sempra Energy	571	1,722
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information Technology	U.S. Gas & Power Renewables	146	125,864
22	Real Estate & Facilities	U.S. Gas & Power Renewables	146	73,208
23	Supply Management	U.S. Gas & Power Renewables	146	6,098
24	Accounting & Finance	Sempra LNG	146	666
25	Depreciation Expense	Sempra LNG	146	19,269
26	Environmental Services	Sempra LNG	146	224
27	Human Resources	Sempra LNG	146	-19,365
28	Information Technology	Sempra LNG	146	130,952
29	Real Estate & Facilities	Sempra LNG	146	114,221
30	Supply Management	Sempra LNG	146	7,588
31	Accounting & Finance	Southern California Gas Company	146	8,524,868
32	Customer Services	Southern California Gas Company	146	1,536,704
33	Depreciation Expense	Southern California Gas Company	146	5,629,074
34	Engineering / Const. Services	Southern California Gas Company	146	1,143,521
35	Environmental Services	Southern California Gas Company	146	368,750
36	External Affairs	Southern California Gas Company	146	829,810
37	Fleet Services	Southern California Gas Company	146	652,326
38	Human Resources	Southern California Gas Company	146	3,366,474
39	Information Technology	Southern California Gas Company	146	82,377,103
40	Real Estate & Facilities	Southern California Gas Company	146	1,718,785
41	Supply Management	Southern California Gas Company	146	1,445,579
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Operation Supervision and Engineering	Sempra Energy	580	48,742
3	Load Dispatching	Sempra Energy	581	5,192
4	Station Expenses	Sempra Energy	582	6

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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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)
5	Overhead Line Expenses	Sempra Energy	583	328
6	Underground Line Expenses	Sempra Energy	584	15
7	Meter Expenses	Sempra Energy	586	8,922
8	Customer Installations Expenses	Sempra Energy	587	127
9	Miscellaneous Distribution Expenses	Sempra Energy	588	245,628
10	Rents	Sempra Energy	589	168
11	Maintenance Supervision and Engineering	Sempra Energy	590	1,655
12	Maintenance of Station Equipment	Sempra Energy	592	346
13	Maintenance of Overhead Lines	Sempra Energy	593	9,389
14	Maintenance of Underground Lines	Sempra Energy	594	-4
15	Maintenance of Meters	Sempra Energy	597	364
16	Maintenance and Miscellaneous Distribution	Sempra Energy	598	98
17	Purification Expenses	Sempra Energy	821	19
18	Operation Supervision and Engineering	Sempra Energy	850	1,034
19	Compressor Station Labor and Expenses	Sempra Energy	853	783
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Mains Expense	Sempra Energy	856	707
3	Maintenance of Mains	Sempra Energy	863	1,276
4	Maintenance of Measuring and Regulating Station Eq	Sempra Energy	865	436
5	Operation Supervision and Engineering	Sempra Energy	870	13,177
6	Distribution Load Dispatching	Sempra Energy	871	640

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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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)
7	Mains and Services Expenses	Sempra Energy	874	8,189
8	Measuring and Regulating Station Expenses—General	Sempra Energy	875	398
9	Customer Installations Expenses	Sempra Energy	879	23,780
10	Distribution Other Expenses	Sempra Energy	880	16,073
11	Maintenance of Mains	Sempra Energy	887	2,976
12	Maintenance of Other Equipment	Sempra Energy	894	3
13	Meter Reading Expenses	Sempra Energy	902	1,911
14	Customer Records and Collection Expenses	Sempra Energy	903	12,660
15	Customer Assistance Expenses	Sempra Energy	908	31,319
16	Miscellaneous Customer Service and Info Exp.	Sempra Energy	910	198,067
17	Administrative and General Salaries	Sempra Energy	920	2,156,740
18	Office Supplies and Expenses	Sempra Energy	921	524,575
19	Outside Services Employed	Sempra Energy	923	42,969,033
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Property Insurance	Sempra Energy	924	332,514
3	Injuries and Damages	Sempra Energy	925	26,804,523
4	Employee Pensions and Benefits	Sempra Energy	926	8,104,857
5	Regulatory Commission Expenses	Sempra Energy	928	476,299
6	Miscellaneous General Expense	Sempra Energy	930.2	533
7	Maintenance of General Plant	Sempra Energy	935	10,732
8	Purchased Power	Energia Sierra Juarez	555	43,750,626

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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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)
9	Construction Work in Progress	Southern California Gas Company	107	12,289,784
10	Other Utility Plant	Southern California Gas Company	118	3,930,853
11	Clearing Accounts	Southern California Gas Company	184	2,520,623
12	Miscellaneous Deferred Debits	Southern California Gas Company	186	4,597
13	Accounts Payable	Southern California Gas Company	232	2,536
14	Miscellaneous Transmission Expenses	Southern California Gas Company	566	1,802
15	Miscellaneous Distribution Expenses	Southern California Gas Company	588	25,705
16	Operation Supervision and Engineering	Southern California Gas Company	850	2,222,141
17	System Control and Load Dispatching	Southern California Gas Company	851	674,199
18	Compressor Station Labor and Expenses	Southern California Gas Company	853	49,960
19	Other Expenses	Southern California Gas Company	859	13,116
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Maintenance Supervision and Engineering	Southern California Gas Company	861	14,551
3	Maintenance of Mains	Southern California Gas Company	863	260,840
4	Maintenance of Compressor Station Equipment	Southern California Gas Company	864	33,879
5	Operation Supervision and Engineering	Southern California Gas Company	870	3,573,089
6	Mains and Services Expenses	Southern California Gas Company	874	16,808
7	Distribution Other Expenses	Southern California Gas Company	880	158,632
8	Maintenance of Mains	Southern California Gas Company	887	137,519
9	Maintenance of Meters and House Regulators	Southern California Gas Company	893	106,017
10	Meter Reading Expenses	Southern California Gas Company	902	77,236

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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)
11	Customer Records and Collection Expenses	Southern California Gas Company	903	2,559,775
12	Supervision	Southern California Gas Company	907	36,404
13	Customer Assistance Expenses	Southern California Gas Company	908	333,851
14	Miscellaneous Customer Service and Info Exp.	Southern California Gas Company	910	122,080
15	Outside Services Employed	Southern California Gas Company	923	61,054,239
16	Injuries and Damages	Southern California Gas Company	925	361,750
17	Employee Pensions and Benefits	Southern California Gas Company	926	75,372
18	Regulatory Commission Expenses	Southern California Gas Company	928	1,441,868
19	Miscellaneous General Expense	Southern California Gas Company	930.2/931/935	1,668,547
20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 2 Column: a

Per the FERC Audit, Docket No. FA12-8-000, the following disclosure is required:
There has been a lack of reporting cost allocation methods since the issuance of Order No. 715 on page 429 relating to the footnote only.

This issue has no financial impact on our financial statements.

San Diego Gas and Electric previously provided footnotes on FERC Page 429 per Order No. 715. However, based on FERC audit findings and detailed information now provided, footnotes in years prior to 2013 were not fully descriptive for cost allocation methods of affiliate support to San Diego Gas and Electric, and San Diego Gas and Electric support to affiliates. In 2013, complete and detailed cost allocation methodology footnotes were provided and will continue to be described in such manner each year.

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

[1] (Rows 2-111)
All non-power goods and services provided by affiliated companies are billed to San Diego Gas and Electric at fully loaded cost.

[2] (Rows 2-79)
Fully loaded costs include all direct expenses, indirect overheads and shared service billing. Shared service non-power goods and service support cost are based on allocation process methodologies for Sempra Energy Corporate Center cost centers. The following information regarding multi-factor and causal-beneficial relationship information was provided by the Sempra Energy Corporate Center Budget and Reporting Manager, and is a summary of the varying methodologies used: Multi-factor basic, also known as "Four-Factor", this method is used by a department for which there is no causal relationship. The Multi-factor basic weights four factors equally for each business unit: Revenues, Operating Expenses, Gross Plant and Investment, and Employees; Multi-factor split, this method divides costs 50% to Utilities, 50% to Global. The Multi-factor (basic) percentages are the basis for the allocation between Southern California Gas Company and San Diego Gas and Electric, and between Global Business Units; Multi-factor Utility, this method uses the same four factors that appear in Multi-factor (basic), but calculates ratios for California utility business units only; Shared asset allocation of depreciation expense associated with capitalized assets at each shared service entity are allocated uniquely depending on its allocation of benefit or supporting purpose; Causal - Headquarters Occupancy, rent, depreciation & ROR related to new headquarters this is allocated based on the square footage directly occupied by the business units. Sempra Energy Corporate Center's direct occupation, except for an executive portion which is retained, is reallocated based on the Multi-Factor Basic. Average - CFO, this method is a weighted average of annual labor budget for departments that report to the CFO; Average - Controller, this method is a weighted average of annual labor budget for departments that report to the Controller; Average - Senior Vice President Human Resources, this method is a weighted average of annual labor budget for departments that report to the Senior Vice President of Human Resources; Average - Senior Vice President of Treasury, this method is a weighted average of annual labor budget for departments that report to the Senior Vice President of Treasury; Average - Vice President External Affairs, this method is a weighted average of annual labor budget for departments that report to the Vice President of External Affairs; Causal - Audit US, this method is based on audit hours planned for each business unit in the coming year. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Corporate Responsibility, this method uses the Multi-factor (basic) allocation as a starting point, and then reduces the percentages to exclude a portion attributed to managing costs which are Retained; Causal CCURE System, this allocation is a weighted average of the number of card readers used per business unit for depreciation of the CCURE 9000 Security System. Sempra Energy Corporate Center units are reallocated

using Multi-factor Basic, resulting in a blended percentage; Causal - Executive Benefits (Southern California Gas Company), direct restricted stock and stock options expense for Southern California Gas Company executives is allocated because some executives are shared by more than one business unit. The percentages reflect a weighted average of each executive's work distribution among business units; Causal - Executive Benefits (San Diego Gas and Electric), direct restricted stock and stock options expense for San Diego Gas and Electric executives is allocated because some executives are shared by more than one business unit. The percentages reflect a weighted average of each executive's work distribution among business units; Causal - Executive Full Time Employee Equivalents, this method allocated the support and administration cost for executive related services using a weighted average of participating officers. Executives are heavily weighted (75%) compared to Directors and Vice Presidents (25%). The Sempra Energy Corporate Center shared service Executives are then Multi-factored (basic) resulting in a blended percentage for each business unit; Causal - Executive Security, this method accounts for the transportation services available to Sempra Energy Corporate Center officers and considers their allocation methods in general. The CEO (retained) has one dedicated driver, while the other 3 drivers are available to other executives and assumes an even allocation of Utility, Global and additional Retained. The result is 25% Utility, 25% Global and 50% Retained for 4 drivers; Causal - Finance, for the Project Finance department, the Director estimates percentages of effort for the business units based on significant projects to be financed in the upcoming period; Causal - Fire Insurance, this method allocates all costs for Fire Insurance based on miles of electrical lines in wildland areas per business unit; Causal - FLP (Financial Leadership Program), this allocation is a weighted average of the employees in the Financial Leadership Program based on the business units they support. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Full Time Employee Equivalents, total Full Time Employee equivalents (FTE’s) are used as the basis for allocation of most Human Resource departmental services provided on behalf of all the business units. The Sempra Energy Corporate Center FTE’s are re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Global Risk, Energy Risk Management estimates the percentage of hours worked on both market risk (energy risk and Dodd Frank) and the credit risk by business unit; Causal - Group Executive Insurance, this method allocates the group executive insurance policy using a weighted average of covered officers, per their assigned business unit. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Headquarter Security, this method allocates the costs of Sempra Energy Corporate Center security, excluding the Headquarter guard service contract, by the Causal - Full Time Employee Equivalent method, and allocates the Headquarter guard service contract by the ratio of employees occupying the Sempra Energy Corporate Center Headquarter building; Causal - Hyperion Financial Management and Consolidation System, this allocation is a weighted average of the headcount of Hyperion Financial Management and Consolidation System users. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Major Projects & Controls, the Major Projects and Controls group allocates its overall costs based on a percentage of direct labor charges for each month; and overall average is estimated for the Plan years. Causal - MyInfo Services Contract, MyInfo services cost is allocated by the number of people in the MyInfo system. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Pension, this method allocates based on the relative value of Sempra’s three major pension funds: San Diego Gas & Electric, Southern California Gas, and Sempra Energy Corporate/Global. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Tax Services, this allocation is a weighted average of the workload of each employee within the Tax department based on an annual time study. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; and, Causal - Treasury, for the Finance department, the Assistant Treasurer estimates percentages of effort for the business units based on significant projects requiring financing or advisory work.

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

3 (Rows 81-111)
Fully loaded costs include all direct expenses, indirect overheads and shared service billing. Shared service non power goods and service support cost are based on allocation process methodologies for 118 Southern California Gas Company cost centers. The following causal beneficial relationship information is a summary of the 23 varying methodologies used: 40 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 24 cost centers used a form of LAN ID counts to determine the shared allocation; 10 cost centers used departmental studies based on current year budgeted activities and/or dollars; 6 cost centers used a form of an allocation that combined amounts of time and resources; 6 cost centers used a form of miles of pipe installed and/or current year by service territory allocations; 5 cost centers used a form of weighted average allocation of the share service employees and activities planned for current year project assignments within the cost center, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 4 cost centers used a form of employee count statistics for support; 3 cost centers used a form of an internal departmental multi factor using LAN ID counts and voice phone or other electronic device counts; 2 cost centers used the existing current year Sempra Energy Corporate Center four factor multi factor allocation which includes weighted averages of operating revenue, operating expenses, gross plant and investment and Full Time Employee equivalent numbers; 2 cost centers used a form of assigning 100% of costs to San Diego Gas and Electric Company in support of business case decisions approved for San Diego Gas and Electric Company's sole benefit; 2 used allocation based on the ratio of gas sent to San Diego Gas and Electric compared to total gas throughput; 2 cost centers used a form of an allocation of space study identifying building square footage assigned; 2 cost centers used a form of gas meter counts and service territory allocations; there was one use by a cost center of each of the remaining allocation methodologies: used a form of an internal departmental multi-factor using contract volume activity; used a summary of legal cases handled in previous year and current year; used a metric of purchasing contracts written between utilities; used a forecast of total connected gas meters; used the number of capital projects assigned weighed by individual asset allocation; used a form of allocation based on revenue share; a form of allocation using number of stakeholders at each utility; an allocation based on the weighted average of total utility gas revenue; used a form of a workload distribution study; and, a form of allocation based on vehicle MRU along with the manager's estimate of employee time.

4 (Row 112-155)
All non-power goods and services provided by San Diego Gas and Electric are billed at fully loaded cost.

5 (Row 112)
Affiliate companies charged by San Diego Gas and Electric for less than $250,000 include: Sempra International, Mexico; and, Sempra International, South America.

6 (Rows 113-155)
Fully loaded costs include all direct expenses, indirect overheads and, where applicable, a labor premium required by the Enova/Pacific Enterprises Merger Decision (D.98-03-073) for shared service billing. The Merger Decision also requires San Diego Gas and Electric to charge employee transfer fees to an affiliated company. Shared service non-power goods and service support cost are based on allocation process methodologies for 123 San Diego Gas and Electric cost centers. The following causal-beneficial relationship information is a summary of the 22 varying methodologies used: 41 cost centers used a form of LAN ID counts to determine the shared allocation; 19 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 13 cost centers used a form of prior year project assignments as a base for the current year distribution, which is adjusted as necessary when current year

projects begin or change and impact the current allocation; 10 cost centers used a form of an allocation of space study identifying building square footage assigned; 7 cost centers used a form of the current year budgeted activities and/or dollars study, which is adjusted as necessary when there are changes that impact the current allocation; 4 cost centers used a form of an allocation of time by Vice President or Director’s assessment of planned current year project assignments within the cost center, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 3 cost centers used a form of Full Time Employee equivalent statistics for support; 3 cost centers used a form of assigning 100% of costs to Southern California Gas Company in support of business case decisions approved for Southern California Gas Company’s sole benefit; 3 cost centers used an allocation of application software login activity and statistics for active accounts; 3 cost centers used the existing current year Sempra Energy Corporate Center four factor multi-factor allocation which includes weighted averages of operating revenue, operating expenses, gross plant and investment and Full Time Employee equivalent numbers; 3 cost centers used a form of an allocation of voice count statistics; 3 cost centers used a form of an allocation using an employee matrix to determine support; 2 cost centers used a form of an allocation of computer and/or server system and resource usage statistics; there was one use by a cost center of each of the remaining allocation methodologies: a ratio of miles of pipe installed existing and/or current year by service territory allocations; assigning 100% of costs to Sempra Energy Corporate Center for facilities maintenance support of Sempra Energy Corporate Center buildings and other facilities; electric and gas meter counts and service territory allocations; a weighted average allocation of Sempra Energy Utility (including both Southern California Gas Company and San Diego Gas and Electric) gas revenue; the number of contracts supported; the weighted average of Office Services budget; projections of the project manager based on anticipated project assignments; the weighted average of employee assignments; and, a Workload Distribution Study.

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Fully loaded costs include all direct expenses, indirect overheads and shared service billing. Shared service non-power goods and service support cost are based on allocation process methodologies for 109
Southern California Gas Company cost centers. The following causal-beneficial relationship information is a summary of the 26 varying methodologies used: 44 cost centers used a form of LAN ID counts to determine the shared allocation; 34 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 13 cost centers used a form of the current year budgeted activities and/or dollars study; 12 cost centers used a form of prior year project assignments as a base for the current year distribution, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 11 cost centers used a form of Full Time Employee equivalent statistics for support; 9 cost centers used a form of miles of pipe installed existing and/or current year by service territory allocations; 8 cost centers used a form of gas meter counts and service territory allocations; 8 cost centers used a form of an allocation based on cases worked by regulated and non-regulated companies; 6 cost centers used an internal departmental multi-factor using LAN ID counts and voice phone or other electronic device counts; 6 cost centers used an allocation of voice phone or other electronic device counts; 5 cost centers used a form of an allocation of space study identifying building square footage assigned; 4 cost centers used a form of weighted average allocation of the share service employees and activities planned for current year project assignments within the cost center, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 3 cost centers used an allocation of computer and/or server system and resource usage statistics; 2 cost centers used a current year study of dedicated shared support activities, which is adjusted as necessary when current year dedicated shared support activities begin or change and impact the current allocation; 2 cost centers used an internal department multi-factor applying meter ratio to specific budgeted activities; 2 cost centers used a form of weighted average of LAN id’s; 2 cost centers used an internal departmental multi-factor using contract volume activity; 2 cost centers used a ratio of miles of distribution;

there was one use by a cost center of each of the remaining allocation methodologies: an allocation of Full Time Employee equivalent statistics for benefit; an internal departmental multi-factor using customer count, employee count and miles of existing pipe installed; a weighted average allocation of Sempra Energy Utility (including both Southern California Gas Company and San Diego Gas and Electric) gas revenue; a unit of allocation using ratio of horsepower in compressors and engines; a form of allocation using number of stakeholders to be reached; an assessment by the Pipeline Safety and Compliance Manager of time spent on Southern California Gas and San Diego Gas and Electric work activities; a current year study of budgeted activities by Affiliate; a weighted average of fleet activity related to maintenance repair units serviced in the prior year; an allocation of time based on volume of items mailed and payments processed; an allocation based on the weighted average of SEU Gas revenue; and, an allocation based on the combination of meters and ratio of miles of pipe.

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Miscellaneous General Expenses	$ 148,976
Rents	862,053
Maintenance of General Plant	657,518
	$1,668,547

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