THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
San Diego Gas & Electric Company	**End of** 2019/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

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

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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

The CPA Certification Statement should:

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

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

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

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

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

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

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

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

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

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

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

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

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

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

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

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

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

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

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

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

(4) 'Person' means an individual or a corporation;

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

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

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

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

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

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent San Diego Gas & Electric Company	02 Year/Period of Report End of 2019/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)* 8330 Century Park Court, San Diego, CA 92123	

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	04/17/2020

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 A. Folkmann		
02 Title SVP, CAO, CFO, Controller & Treas	Bruce A. Folkmann	04/17/2020

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.

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".

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	04/17/2020	End of 2019/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".

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	04/17/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

GENERAL INFORMATION

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

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

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	04/17/2020	End of 2019/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.

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			
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				

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	04/17/2020	End of 2019/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	Chief Executive Officer	Sagara, Kevin C.	540,300
2	President	Drury, Scott D.	514,500
3	Chief Operating Officer	Winn, Caroline A.	455,200
4	Senior Vice President, Chief Financial Officer,	Folkmann, Bruce A.	339,900
5	Chief Accounting Officer, Controller, Treasurer		
6	Senior Vice President - Chief Information Officer and	Chase, Kevin P.	473,700
7	Chief Digital Officer (2)		
8	Vice President, General Counsel, Chief Risk Officer (3)	Day, Diana L.	335,000
9	Chief Human Resources Officer and Chief Administrative	Clark, Randall L.	318,600
10	Officer (4)		
11	Corporate Secretary (5)	McCulloch, Kari	255,000
12	Corporate Secretary (6)	Robinson, April R.	241,565
13			
14	(1) Does not include bonuses and other forms of		
15	compensation.		
16			
17	(2) Resigned 4/2/2019		
18			
19	(3) Appointed as executive officer 1/12/2019		
20			
21	(4) Resigned 4/5/2019		
22			
23	(5) Resigned 11/3/2019		
24			
25	(6) Appointed 11/4/2019		
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
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	04/17/2020	End of 2019/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	Kevin C. Sagara, Director and Chief Executive Officer	San Diego, CA
2	Robert J. Borthwick, Director (1)	San Diego, CA
3	Scott D. Drury, Director (2) and President	San Diego, CA
4	Erbin B. Keith, Director (1)	San Diego, CA
5	Trevor I. Mihalik, Director (1)	San Diego, CA
6	G. Joyce Rowland, Director(1) (3)	San Diego, CA
7	Caroline A. Winn, Director (2) and Chief Operating Officer	San Diego, CA
8	Martha B. Wyrsch, Director (1) (4)	San Diego, CA
9		
10	(1) Do not hold any offices with SDG&E but are officers of	
11	SDG&E's ultimate parent, Sempra Energy.	
12		
13	(2) Resigned as director 7/17/2019	
14		
15	(3) Resigned/retired 10/31/2019	
16		
17	(4) Resigned/retired 3/1/2019	
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		
47		
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	04/17/2020	End of 2019/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] 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	FERC Electric Tariff, Volume No.11	ER19-209-000
2		
3		
4	FERC Electric Tariff, Volume No.11	ER19-221-000
5		
6	FERC Electric Tariff, Volume No.11	ER19-512-000
7		
8		
9	FERC Electric Tariff, Volume No.11	ER19-558-000
10		
11		
12	FERC Electric Tariff, Volume No.11	ER19-1513-000
13		
14	FERC Electric Tariff, Volume No.11	ER19-2017-000
15		
16	FERC Electric Tariff, Volume No.11	ER19-1513-001
17		
18	FERC Electric Tariff, Volume No.11	ER19-221-002
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

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	04/17/2020	End of 2019/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] 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	20181029-5122	10/29/2018	ER19-209-000	2019 Transmission Revenue Balancing	FERC Electric Tariff, Volume No.11
2				Adjustment ("TRBAA") Filing	
3					
4	20181030-5125	10/30/2018	ER19-221-000	TO5 Cycle 1 Formula Rate Tariff Filing	FERC Electric Tariff, Volume No.11
5					
6	20181207-5027	12/07/2018	ER19-512-000	2019 Transmission Access Charge	FERC Electric Tariff, Volume No.11
7				Adjustment ("TACBAA") Filing	
8					
9	20181214-5098	12/14/2018	ER19-558-000	2019 Reliability Service Balancing	FERC Electric Tariff, Volume No.11
10				("RSBA") Filing	
11					
12	20190402-5210	04/02/2019	ER19-1513-000	Appendix XII Cycle 1 Formula Rate	FERC Electric Tariff, Volume No.11
13					
14	20190530-5522	05/30/2019	ER19-2017-000	Appendix X Cycle 8 Informational Filing	FERC Electric Tariff, Volume No.11
15					
16	20190627-5199	06/27/2019	ER19-1513-001	Appendix XII Formula Rate Protocols	FERC Electric Tariff, Volume No.11
17					
18	20191018-5121	10/18/2019	ER19-221-002	TO5 Offer of Settlement Filing	FERC Electric Tariff, Volume No.11
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					

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	04/17/2020	End of 2019/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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

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.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None

2. None

3. None

4. SDG&E extended the term of its Right of Entry Agreement for space located at 1010 Tavern Road on 11/07/2019. New term extends from 01/01/2020-12/31/2020. Monthly rent starting 01/01/2020 will be $11,827.35.

5. In the fourth quarter of 2019, notable changes to the Transmission System included:

   Transmission Line TL 663 from Mission Substation to Kearny West Substation converted 3.72 miles of overhead conductors to underground.

   Transmission Line TL 633 from Bernardo Substation to Rancho Carmel Substation converted 2.97 miles of overhead conductors to underground.

6. During the first quarter of 2019, SDG&E issued commercial paper with an average daily balance of $264.7 million and a maximum outstanding balance of $319.4 million. The quarter-end balance was $237.7 million.

   During the second quarter of 2019, SDG&E issued commercial paper with an average daily balance of $231.1 million and a maximum outstanding balance of $416.9 million. The quarter-end balance was $18.5 million.

   In the second quarter, SDG&E issued $400 million of 4.10% first mortgage bonds on 05/31/2019, maturing in 2049.

   During the third quarter of 2019, SDG&E issued commercial paper with an average daily balance of $3.4 million and a maximum outstanding balance of $36 million. The quarter-end balance was $0.

   During the fourth quarter of 2019, SDG&E issued commercial paper with an average daily balance of $10.8 million and a maximum outstanding balance of $79.8 million. The year-end balance was $79.8 million.

7. None

8. On 09/01/2019, SDG&E employees represented by the International Brotherhood of Electrical Workers (IBEW) Local 465 received a negotiated base rate increase of 3.25%, affecting 1314 employees:

   Total annualized base wages for represented employees in 2019 is $7.4 million above 2018 base wages.

   Total annualized wages for represented employees including overtime in 2019 is $16.5 million above 2018 wages including overtime.

9. Please refer to the Legal Proceedings sections of the Notes to the Financial Statements on page 123.68.

10. None

11. N/A

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

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	04/17/2020	2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

13. Changes in Officers:

Name	Title	Effective Date
Jimmie I. Cho	Senior Vice President - Gas Distribution Operations	Resigned, 01/01/2019
Diana L. Day	Vice President - Enterprise Risk Management and Compliance and Acting General Counsel to Vice President and General Counsel	Changed, 01/12/2019
M. Angelica Espinosa	Assistant Secretary to Vice President and Chief Risk Officer	Changed, 01/12/2019
Cedric Williams	Vice President - Construction	Appointed, 01/28/2019
Rodger R. Schwecke	Senior Vice President - Gas Transmission & Engineering to Senior Vice President - Gas Operations and Construction	Changed, 03/09/2019
John D. Jenkins	Vice President - Electric Engineering and Construction to Vice President - Electric Operations and Major Construction	Changed, 03/09/2019
John D. Jenkins	Vice President - Electric Operations and Major Construction to Vice President - Electric Systems Operations	Changed, 03/16/2019
William H. Speer	Vice President - Electric Engineering and Construction	Appointed, 03/16/2019
Katherine M. Speirs	Vice President - Electric System Operations	Resigned, 03/20/2019
P. Kevin Chase	Senior Vice President - Chief Information Officer and Chief Digital Officer	Resigned, 04/02/2019
Randall L. Clark	Chief Administrative Officer and Chief Human Resources Officer	Resigned, 04/05/2019
Karen L. Sedgwick	Chief Administrative Officer and Chief Human Resources Officer	Appointed, 04/20/2019
Rajan Agarwal	Assistant Controller	Appointed, 06/15/2019
Donny Widjaja	Assistant Treasurer	Resigned, 07/26/2019
M. Angelica Espinosa	Vice President and Chief Risk Officer	Resigned, 08/09/2019
Denita A. Willoughby	Vice President - Supply Management	Resigned, 08/09/2019
Diana L. Day	Vice President, General Counsel and Assistant Secretary to Vice President, General Counsel, Chief Risk Officer and	Changed, 08/10/2019

	Assistant Secretary	
Estela de Llanos	Vice President - Operations, Sustainability and Chief Environmental Officer to Vice President - Clean Transportation, Sustainability and Chief Environmental Officer	Changed, 08/10/2019
Bruce A. Folkmann	Chief Financial Officer, Vice President, Controller, Chief Accounting Officer and Treasurer to Chief Financial Officer, Senior Vice President, Controller, Chief Accounting Officer and Treasurer	Changed, 08/10/2019
Kendall K. Helm	Vice President - Energy Supply to Vice President - Customer Operations	Changed, 08/10/2019
Michael M. Schneider	Vice President - Clean Transportation and Asset Management to Vice President - Risk Management and Compliance	Changed, 08/10/2019
Miguel Romero	Vice President - Energy Supply	Elected, 08/10/2019
Christina H. Ihrig	Vice President - Operations Support	Elected, 08/10/2019
Jennifer F. Jett	Assistant Secretary	Elected, 08/10/2019
James M. Spira	Assistant Secretary	Resigned, 09/20/2019
David L. Buczkowski	Vice President - Gas Engineering & System Integrity to Vice President - Gas Distribution	Changed, 10/19/2019
G. Orozco-Mejia	Vice President - Gas Distribution to Vice President - Gas Engineering and System Integrity	Changed, 10/19/2019
Kari E. McCulloch	Corporate Secretary	Resigned, 11/03/2019
April R. Robinson	Corporate Secretary	Elected, 11/04/2019

Changes in Directors:

Name	Title	Effective Date
Martha B. Wyrsch	Director	Resigned, 03/01/2019
Scott D. Drury	Director	Resigned, 07/17/2019
Caroline A. Winn	Director	Resigned, 07/17/2019
Robert J. Borthwick	Director	Appointed, 07/18/2019
Erbin B. Keith	Director	Appointed, 07/18/2019

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	(Mo, Da, Yr) 04/17/2020	2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

G. Joyce Rowland Director Resigned, 10/31/2019

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	04/17/2020	End of 2019/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	21,175,191,550	20,491,384,467
3	Construction Work in Progress (107)	200-201	1,500,632,606	1,219,293,740
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		22,675,824,156	21,710,678,207
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	7,079,972,729	6,787,171,251
6	Net Utility Plant (Enter Total of line 4 less 5)		15,595,851,427	14,923,506,956
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)		15,595,851,427	14,923,506,956
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,030,598	6,030,598
19	(Less) Accum. Prov. for Depr. and Amort. (122)		326,050	326,050
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	189,218,523	155,016,001
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)		1,082,406,303	973,933,996
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		75,216,693	232,394,419
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,352,546,067	1,367,048,964
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,497,400	7,252,036
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		500	500
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		324,851,251	302,508,480
41	Other Accounts Receivable (143)		118,663,035	106,130,463
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,956,390	5,015,424
43	Notes Receivable from Associated Companies (145)		28,780	-12
44	Accounts Receivable from Assoc. Companies (146)		198,903	217,142
45	Fuel Stock (151)	227	0	0
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	131,837,616	136,203,688
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	202,302,974	170,495,651

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	04/17/2020	End of 2019/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		189,218,523	155,016,001
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		490,246	361,245
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		2,879	6,219
57	Prepayments (165)		225,297,312	76,241,970
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		2,424,633	2,433,968
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		76,706,000	70,728,000
62	Miscellaneous Current and Accrued Assets (174)		32,679,971	3,700,000
63	Derivative Instrument Assets (175)		118,060,990	314,735,501
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		75,216,693	232,394,419
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)		975,650,884	798,589,007
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		35,819,230	34,501,516
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	1,366,481
72	Other Regulatory Assets (182.3)	232	2,222,440,130	1,810,362,978
73	Prelim. Survey and Investigation Charges (Electric) (183)		969,994	813,362
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)		133,106	-1,231,487
77	Temporary Facilities (185)		640,360	629,731
78	Miscellaneous Deferred Debits (186)	233	485,680,679	108,837,345
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)		4,654,464	6,483,720
82	Accumulated Deferred Income Taxes (190)	234	143,667,662	147,260,603
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,894,005,625	2,109,024,249
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		20,818,054,003	19,198,169,176

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

The 13-month Average Electric Prepayments for 2019 is $70,057,189.

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	04/17/2020	end of 2019/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	802,165,368	479,665,368
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	5,454,653,820	4,683,700,304
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)	-15,874,048	-9,578,079
16	Total Proprietary Capital (lines 2 through 15)		7,099,080,873	6,011,923,326
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	5,140,552,000	4,776,266,000
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	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		12,166,400	12,609,585
24	Total Long-Term Debt (lines 18 through 23)		5,128,385,600	4,763,656,415
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,350,522,358	1,254,952,617
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		25,612,689	25,902,087
29	Accumulated Provision for Pensions and Benefits (228.3)		157,869,828	217,186,910
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		66,790,512	97,429,293
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		865,801,344	872,109,559
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,466,596,731	2,467,580,466
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		79,768,524	290,971,029
38	Accounts Payable (232)		544,593,815	478,117,692
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		53,342,342	60,547,337
41	Customer Deposits (235)		84,085,883	82,186,953
42	Taxes Accrued (236)	262-263	561,420	29,872,707
43	Interest Accrued (237)		42,855,491	42,378,076
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	04/17/2020	end of 2019/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)		5,857,373	5,310,800
48	Miscellaneous Current and Accrued Liabilities (242)		194,863,373	176,709,521
49	Obligations Under Capital Leases-Current (243)		47,248,331	329,962,233
50	Derivative Instrument Liabilities (244)		95,872,552	134,348,425
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		66,790,512	97,429,293
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,082,258,592	1,532,975,480
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		67,517,371	51,804,881
57	Accumulated Deferred Investment Tax Credits (255)	266-267	14,428,349	15,623,118
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	492,083,275	321,262,586
60	Other Regulatory Liabilities (254)	278	2,478,762,436	2,301,355,349
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)		1,771,607,192	1,651,155,259
64	Accum. Deferred Income Taxes-Other (283)		217,333,584	80,832,296
65	Total Deferred Credits (lines 56 through 64)		5,041,732,207	4,422,033,489
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		20,818,054,003	19,198,169,176

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	04/17/2020	End of 2019/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	5,308,696,913	5,132,471,203		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,111,284,012	3,176,303,937		
5	Maintenance Expenses (402)	320-323	194,086,509	157,916,904		
6	Depreciation Expense (403)	336-337	622,724,838	566,472,786		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	96,619,384	87,577,972		
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)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		2,866,297	2,334,790		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	160,990,560	146,482,506		
15	Income Taxes - Federal (409.1)	262-263	42,623,707	106,373,570		
16	- Other (409.1)	262-263	35,042,898	30,765,105		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	271,389,436	242,146,627		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	169,793,899	206,348,948		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,194,769	-2,016,932		
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)		4,366,654,717	4,308,024,061		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		942,042,196	824,447,142		

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	04/17/2020	End of 2019/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
4,644,412,166	4,564,474,007	662,104,353	570,095,663	2,180,394	-2,098,467	2
						3
2,705,281,818	2,821,320,974	408,920,855	359,303,243	-2,918,661	-4,320,280	4
167,050,456	134,272,155	27,036,053	23,644,749			5
547,243,218	499,241,280	72,408,535	65,298,687	3,073,085	1,932,819	6
						7
75,620,668	71,592,556	20,998,716	15,985,416			8
15,744	15,744					9
						10
						11
1,651,351	1,326,640	1,214,946	1,008,150			12
						13
137,773,189	125,403,825	22,493,773	20,422,825	723,598	655,856	14
49,576,298	93,320,720	-6,952,591	13,052,850			15
36,785,557	27,732,020	-1,742,659	3,033,085			16
245,194,856	222,542,113	26,194,580	19,604,514			17
160,779,928	180,963,984	9,013,971	25,384,964			18
-986,264	-1,504,003	-208,505	-512,929			19
						20
						21
						22
						23
						24
3,804,426,963	3,814,300,040	561,349,732	495,455,626	878,022	-1,731,605	25
839,985,203	750,173,967	100,754,621	74,640,037	1,302,372	-366,862	26

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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)		942,042,196	824,447,142		
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)					
34	(Less) Expenses of Nonutility Operations (417.1)		7,541,623	314		
35	Nonoperating Rental Income (418)		31,727	33,415		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		28,026,149	15,377,549		
38	Allowance for Other Funds Used During Construction (419.1)		57,453,742	59,969,625		
39	Miscellaneous Nonoperating Income (421)		626,789	763,823		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		78,596,784	76,144,098		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		250,048	250,048		
45	Donations (426.1)		13,057,930	7,362,363		
46	Life Insurance (426.2)		-6,732,058	-6,000,301		
47	Penalties (426.3)		36,409	10,000		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,322,364	2,420,843		
49	Other Deductions (426.5)		24,034,646	20,509,706		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		33,969,339	24,552,659		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	738,412	700,161		
53	Income Taxes-Federal (409.2)	262-263	-8,389,469	-1,747,422		
54	Income Taxes-Other (409.2)	262-263	-3,883,973	-883,667		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	8,089,310	8,412,437		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,199,039	3,426,173		
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)		-6,644,759	3,055,336		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		51,272,204	48,536,103		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		213,846,544	200,012,289		
63	Amort. of Debt Disc. and Expense (428)		3,709,481	3,450,807		
64	Amortization of Loss on Reaquired Debt (428.1)		1,831,091	2,799,425		
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)					
68	Other Interest Expense (431)		24,531,380	20,172,691		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		19,787,739	20,320,891		
70	Net Interest Charges (Total of lines 62 thru 69)		224,130,757	206,114,321		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		769,183,643	666,868,924		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		769,183,643	666,868,924		

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	04/17/2020	2019/Q4

FOOTNOTE DATA

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	$ (4,204,395)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	6,384,789
	$ 2,180,394

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

Eliminates interdepartmental transfers	$ (4,204,396)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	6,384,789
	$ (2,098,467)

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

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

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

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

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

Eliminates interdepartmental transfers	$ (2,204,396)
Citizens Energy Corporation Operating Expenses	1,285,735
	$ (2,918,661)

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

Eliminates interdepartmental transfers	$ (5,531,512)
Citizens Energy Corporation Operating Expenses	1,211,233
	$ (4,320,280)

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

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	236,124
	$ 3,073,085

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

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	(904,141)
	$ 1,932,819

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

Citizens Energy Corporation Property Tax	$ 699,382
Citizens Energy Corporation Payroll Tax	24,215
	$ 723,598

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

Citizens Energy Corporation Property Tax	$ 631,559
Citizens Energy Corporation Payroll Tax	24,297
	$ 655,856

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

Modification of the Allowance 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.

During the year, the average amount of short-term debt directly related to its balancing and memo accounts net under-collections excluded from the calculation of AFUDC rate, amount to $72.7 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $21.8 million.

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

Modification of the Allowance 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.

During the year, the average amount of short-term debt directly related to its balancing and memo accounts net under-collections excluded from the calculation of AFUDC rate, amount to $145.9 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $11.5 million.

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

Modification of the Allowance 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.

During the year, the average amount of short-term debt directly related to its balancing and memo accounts net under-collections excluded from the calculation of AFUDC rate, amount to $72.7 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $21.8 million.

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

Modification of the Allowance 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.

During the year, the average amount of short-term debt directly related to its balancing and memo accounts net under-collections excluded from the calculation of AFUDC rate, amount to $145.9 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $11.5 million.

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		4,683,700,304	4,266,831,380
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	ASU 2018-02 Stranded Tax Effects		1,769,873	
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		1,769,873	
16	Balance Transferred from Income (Account 433 less Account 418.1)		769,183,643	666,868,924
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				(250,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(250,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		5,454,653,820	4,683,700,304
	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	04/17/2020	End of 2019/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)		5,454,653,820	4,683,700,304
	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)			

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	04/17/2020	End of 2019/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)	769,183,643	666,868,924
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	622,724,838	566,472,786
5	Amortization of Unrecovered Plant and Regulatory Study Costs	96,635,128	87,593,716
6	Impairment - Disallowed Costs from 2019 GRC FD	6,320,399	
7			
8	Deferred Income Taxes (Net)	106,485,809	40,783,943
9	Investment Tax Credit Adjustment (Net)	-1,194,769	-2,016,932
10	Net (Increase) Decrease in Receivables	-41,894,139	-33,108,384
11	Net (Increase) Decrease in Inventory	4,240,410	4,376,494
12	Net (Increase) Decrease in Allowances Inventory	-45,587,670	-95,994,355
13	Net Increase (Decrease) in Payables and Accrued Expenses	51,276,102	15,555,859
14	Net (Increase) Decrease in Other Regulatory Assets	-446,450,613	-31,043,220
15	Net Increase (Decrease) in Other Regulatory Liabilities	322,504,043	296,280,836
16	(Less) Allowance for Other Funds Used During Construction	57,453,742	59,969,625
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: Net (Increase) Decrease in Prepayments and Other	-184,920,300	-17,661,648
19	Net Increase (Decrease) in Accrued Interest and Taxes	254,408	23,153,154
20	Wildfire Fund	-322,500,000	
21	Other - Net	147,609,767	104,479,498
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,027,233,314	1,565,771,046
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,579,052,227	-1,598,598,989
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	-57,453,742	-59,969,625
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,521,598,485	-1,538,629,364
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	598,033	1,054
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	COLI - Corporate Owned Life Insurance	7,052,078	
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	04/17/2020	End of 2019/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	Decommissioning Trust Fund Purchase	-913,881,645	-890,292,254
54	Decommissioning Trust Fund Sales	913,881,645	890,292,254
55	Increase (Decrease) in Customer Advances for Construction	19,140,928	-14,143,395
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,494,807,446	-1,552,771,705
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	399,580,000	398,231,598
62	Preferred Stock		
63	Common Stock		
64	Other: LTD Issuance Cost	-4,344,000	-3,500,000
65	Other: Equity Contribution from Sempra Energy	322,500,000	
66	Net Increase in Short-Term Debt (c)	-211,202,504	38,337,023
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	506,533,496	433,068,621
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-35,714,000	-196,914,303
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		-250,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	470,819,496	-13,845,682
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	3,245,364	-846,341
87			
88	Cash and Cash Equivalents at Beginning of Period	7,252,536	8,098,877
89			
90	Cash and Cash Equivalents at End of period	10,497,900	7,252,536

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.

NOTES TO FINANCIAL STATEMENTS

A. Notes for Statement of Cash Flows:

Supplemental Disclosure of Cash Flow Information:				12/31/2019
Income tax payments (refunds), net			$	190,990,994
Interest payments, net of amounts capitalized			$	394,040,005
Reconciliation of Cash and Cash Equivalents at December 31, 2019:				
	Account 131	Cash	$	10,497,400
	Account 135	Working Funds	$	500
	Account 136	Temporary Cash Investments		-
			$	10,497,900

Supplemental Disclosure of Non-Cash Investing Activities:

Increase (Decrease) in finance lease (PPA & Fleet) obligation for investments in property, plant and equipment	$	15,677,361
Accrued Capital Expenditures	$	174,157,000

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, 2019, as filed with the SEC on February 27, 2020. 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 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 U.S. GAAP. The principal differences of this basis of accounting from U.S. 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 reserves
- 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
- Certain plant in service, accumulated depreciation, and regulatory assets
- Certain pension costs between other income and A&G
- Certain balance sheet treatment for operating lease for U.S. GAAP purposes are reported under Property Under Capital Leases, Amortization and Capital Lease Obligations.
- Certain lease expenses between depreciation, interest expenses, and other line items.

Accordingly, certain Notes to the Financial Statements are not reflective of SDG&E's Financial Statements contained herein, which have been prepared on a stand alone basis, which exclude consolidation with OMEC LLC's 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 U.S. GAAP reporting requirements as mentioned above, certain amounts disclosed in Notes 1-13 may not agree to balances in the FERC financial statements.

C. Other FERC Related Disclosures

FERC Capital Leases

The following agreement was accounted for as a capital lease under FERC accounting requirements and as a variable interest entity under U.S. GAAP requirements through August 23, 2019.

OMEC LLC PPA

We had an agreement through August 23, 2019 to purchase power generated at OMEC, a 573-megawatt generating facility that began commercial operation in October 2009. We supplied all of the natural gas to fuel the power plant, and we purchased its full electric generation output. The agreement was recorded as a capital lease through August 23rd, 2019 and was removed from the balance sheet upon completion of the contract.

D. COVID-19

The coronavirus (COVID-19) global pandemic currently affecting the United States and elsewhere has resulted in significant impacts on the global economy that could affect our operations in a manner that is not presently possible to predict and could have a material adverse effect on our financial condition, results of operations, and cash flows.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

BASIS OF PRESENTATION

This is a report of SDG&E. SDG&E's common stock is wholly owned by Enova, which is a wholly owned subsidiary of Sempra Energy. References in this report to "we," and "our" are to SDG&E, unless otherwise indicated by the context.

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, 2019 through 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 and financial statements reflect the application of U.S. GAAP provisions governing rate-regulated operations and the policies of the CPUC and the FERC. 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 of regulatory assets 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

▪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

▪Historical experience

We provide information concerning regulatory assets and liabilities in Note 4.

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.

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 – Pricing inputs are unadjusted quoted prices 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 and U.S. government treasury securities, primarily in the NDT 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 and 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 listed equities, domestic corporate bonds, and municipal bonds, primarily in the NDT and benefit plan trusts.

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 CRRs and fixed-price electricity positions.

CASH AND CASH EQUIVALENTS

Cash equivalents are highly liquid investments with original 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,		
	2019	2018	2017
Allowances for collection of receivables at January 1	$ 11	$ 9	$ 8
Provisions for uncollectible accounts	10	9	8
Write-offs of uncollectible accounts	(7)	(7)	(7)
Allowances for collection of receivables at December 31	$ 14	$ 11	$ 9

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 collection allowances 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.

CONCENTRATION OF CREDIT RISK

Credit risk is the risk of loss that would be incurred as a result of nonperformance by our counterparties on their contractual obligations. We have policies governing the management of credit risk that are administered by our credit department and overseen by our risk management committee.

This oversight includes calculating current and potential credit risk on a daily basis and monitoring actual balances in comparison to approved limits. We establish credit limits based on risk and return considerations under terms customarily available in the industry. We avoid concentration of counterparties whenever possible, and we believe our credit policies significantly reduce overall credit risk. These policies include an evaluation of:

- prospective counterparties’ financial condition (including credit ratings)
- collateral requirements
- the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty
- downgrade triggers

We believe that we have provided adequate reserves for counterparty nonperformance.

When our development projects become operational, we rely significantly on the ability of suppliers to perform under long-term agreements and on our ability to enforce contract terms in the event of nonperformance. Also, the factors that we consider in evaluating a development project include negotiating customer and supplier agreements and, therefore, we rely on these agreements for future performance. We also may condition our decision to go forward on development projects on first obtaining these customer and supplier agreements.

INVENTORIES

We value natural gas inventory using the 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 are as follows:

INVENTORY BALANCES AT DECEMBER 31
(Dollars in millions)

	Natural gas		Materials and supplies		Total	
	2019	2018	2019	2018	2019	2018
SDG&E	$ 1	$ —	$ 93	$ 98	$ 94	$ 98

WILDFIRE FUND

On July 12, 2019, the Wildfire Legislation was signed into law. The Wildfire Legislation addresses certain issues related to catastrophic wildfires in the State of California and their impact on electric IOUs. The issues addressed include wildfire mitigation, cost recovery standards and requirements, a wildfire fund, a cap on liability, and the establishment of a wildfire safety board.

The Wildfire Legislation requires SDG&E to install at least $215 million of fire risk mitigation capital improvements, which will be the first $215 million of capital included in its wildfire mitigation plan, and recover its financing costs without a ROE.

The Wildfire Legislation established a revised legal standard for the recovery of wildfire costs (Revised Prudent Manager Standard) and established a fund (the Wildfire Fund) to provide liquidity to SDG&E, PG&E and Edison to pay IOU wildfire-related claims in the event that the governmental agency responsible for determining causation determines the applicable IOU's equipment caused the ignition of a wildfire, the primary insurance coverage is exceeded and certain other conditions are satisfied. The primary purpose of the Wildfire Fund is to pool resources provided by shareholders and ratepayers of the IOUs and make those resources available to reimburse the IOUs for third-party wildfire claims incurred after July 12, 2019, the effective date of the Wildfire Legislation, subject to certain limitations.

An IOU may seek payment from the Wildfire Fund for settled or adjudicated third-party damage claims arising from certain wildfires that exceed, in aggregate in a calendar year, the greater of $1 billion or the IOU's required amount of insurance coverage as recommended by the Wildfire Fund's administrator. Wildfire claims approved by the Wildfire Fund's administrator will be paid by the Wildfire Fund to the IOU to the extent funds are available. These utilized funds will be subject to review by the CPUC, which will make a determination as to the degree an IOU's conduct related to an ignition of a wildfire was prudent or imprudent. The Revised Prudent Manager Standard requires that the CPUC apply clear standards when reviewing wildfire liability losses paid when determining the reasonableness of an IOU's conduct related to an ignition. Under this standard, the conduct under review related to the ignition may include factors within and beyond the IOU's control, including humidity, temperature and winds. Costs and expenses may be allocated for cost recovery in full or in part. Also, under this standard, an IOU's conduct will be deemed reasonable if a valid annual safety certification is in place at the time of the ignition, unless a serious doubt is raised, in which case the burden shifts to the utility to dispel that doubt. The IOUs will receive an annual safety certification from the CPUC if they meet various requirements.

If an IOU has maintained a valid annual safety certification, to the extent it is found to be imprudent, claims will be reimbursable by the IOU to the Wildfire Fund up to a cap based on the IOU's rate base. The aggregate requirement to reimburse the Wildfire Fund over a trailing three calendar year period is capped at 20% of the equity portion of an IOU's electric transmission and distribution rate base in the year of the prudency determination. SDG&E received its annual safety certification from the CPUC on July 26, 2019, which is valid for 12 months. Based on its 2019 rate base, the liability cap for SDG&E is approximately $900 million, which will be adjusted annually. The liability cap will apply on a rolling three-year basis so long as future annual safety certifications are received and the Wildfire Fund has not been terminated, which could occur if funds are exhausted. Amounts in excess of the liability cap and amounts that are determined to be prudently incurred do not need to be reimbursed by an IOU to the Wildfire Fund. The Wildfire Fund does not have a specified term and coverage will continue until the assets of the Wildfire Fund are exhausted and the Wildfire Fund is terminated, in which case, the remaining funds will be transferred to California's general fund to be used for fire risk mitigation programs.

The Wildfire Fund could initially be funded up to $10.5 billion by a loan from the State of California Surplus Money Investment Fund. Such lending will subsequently be financed through an anticipated DWR bond, securitized through a dedicated surcharge on ratepayers' bills attributable to the DWR. In October 2019, the CPUC adopted a decision authorizing a non-bypassable charge to be collected by the IOUs to support the anticipated DWR bond issuance authorized by AB 1054. The CPUC decision also determined that ratepayers of non-participating electrical corporations shall not pay the non-bypassable charge. PG&E has agreed to participate in the Wildfire Fund, subject to bankruptcy court approval. Accordingly, if PG&E is unable to participate in the Wildfire Fund, its customers will not pay the non-bypassable charge, resulting in significantly lower Wildfire Fund contributions from ratepayers than the anticipated $10.5 billion.

The Wildfire Fund could also be funded by up to $7.5 billion in initial shareholder contributions from the IOUs (SDG&E's share is $322.5 million, PG&E's share is $4.8 billion and Edison's share is $2.4 billion). The IOUs could also be required to make annual shareholder contributions to the Wildfire Fund with an aggregate value of $3 billion over a 10-year period (SDG&E's share is $129 million, PG&E's share is $1.9 billion and Edison's share is $945 million). If PG&E is unable to participate in the Wildfire Fund, SDG&E's and Edison's aggregate shareholder contributions to the Wildfire Fund will not change and are expected to total approximately $3.8 billion. When estimating the period of benefit of the Wildfire Fund asset that we discuss below, we assume PG&E will participate in the Wildfire Fund. The contributions are not subject to rate recovery.

SDG&E paid its initial shareholder contribution of $322.5 million to the Wildfire Fund in September 2019. SDG&E funded this contribution with proceeds from an equity contribution from Sempra Energy. Sempra Energy funded the equity contribution to SDG&E with proceeds from settling forward sale agreements through physical delivery of shares of Sempra Energy common stock in exchange for cash. Edison paid its initial shareholder contribution in September 2019.

In a complaint filed in U.S. District Court for the Northern District of California in July 2019, plaintiffs seek to invalidate AB 1054 based on allegations that the legislation violates federal law. The California Attorney General has moved to dismiss the complaint.

Wildfire Fund Asset

SDG&E recorded a Wildfire Fund asset for its commitment to make shareholder contributions totaling $451.5 million, measured at present value as of July 25, 2019 (the date by which both Edison and SDG&E opted to contribute to the Wildfire Fund). SDG&E is amortizing the Wildfire Fund asset to O&M on a straight-line basis over the estimated period of benefit, as adjusted for utilization by the IOUs. The estimated period of benefit of the Wildfire Fund asset, which is 15 years as of December 31, 2019, is based on several assumptions, including, but not limited to:

- historical wildfire experience of each IOU in the State of California, including frequency and severity of the wildfires
- the value of property potentially damaged by wildfires
- the effectiveness of wildfire risk mitigation efforts by each IOU
- liability cap of each IOU
- IOU prudency determination levels
- FERC jurisdictional allocation levels
- insurance coverage levels

The use of different assumptions, or changes to the assumptions used, could have a significant impact on the estimated period of benefit of the Wildfire Fund asset.

We will periodically reevaluate the estimated period of benefit of the Wildfire Fund asset based on actual experience and changes in the above assumptions. SDG&E may recognize a reduction of its Wildfire Fund asset and record a charge against earnings in the period when there is a reduction of the available coverage due to recoverable claims from the IOUs. The reduction to the Wildfire Fund asset may be proportionate to the Wildfire Fund's consumption (i.e., recoveries for outstanding wildfire claims that are recoverable from the Wildfire Fund, net of anticipated or actual reimbursement to the Wildfire Fund by the responsible IOU, would decrease the Wildfire Fund asset and remaining available coverage). At December 31, 2019, there were no such known claims from the IOUs requiring a reduction of the Wildfire Fund asset.

At December 31, 2019, the current portion of the Wildfire Fund asset was $29 million in Miscellaneous Current and Accrued Assets on SDG&E's Balance Sheet, and the noncurrent portion of $392 million was in Miscellaneous Deferred Debits on SDG&E's Balance Sheet.

Wildfire Fund Obligation

SDG&E recorded a Wildfire Fund obligation for its commitment to make shareholder contributions totaling $451.5 million, measured at present value as of July 25, 2019 (the date by which both Edison and SDG&E opted to contribute to the Wildfire Fund). SDG&E paid its initial shareholder contribution of $322.5 million to the Wildfire Fund in September 2019 and its first annual shareholder contribution of $12.9 million in December 2019. At December 31, 2019, SDG&E expects to make annual shareholder contributions of $12.9 million in each of the next nine years. SDG&E accretes the present value of the Wildfire Fund obligation to O&M until the liability is settled.

At December 31, 2019, the Wildfire Fund obligation was $12.9 million in Other Current Liabilities and $86 million in Deferred Credits and Other on SDG&E's Balance Sheet.

INCOME TAXES

Income tax expense includes current and deferred income taxes. We record deferred income taxes for temporary differences between the book and the tax basis of assets and liabilities. ITCs 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, we recognize:

- regulatory assets to offset deferred income tax liabilities if it is probable that the amounts will be recovered from customers; and
- regulatory liabilities to offset deferred income 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%. 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% likely of being realized upon its effective resolution.

Unrecognized income 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 ETR.

We provide additional information about income taxes in Note 6.

GREENHOUSE GAS ALLOWANCES AND OBLIGATIONS

SDG&E is required by AB 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 on behalf of our customers at no cost. We record purchased and allocated GHG allowances at the lower of weighted-average cost or market. 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. We remove the assets and liabilities from the balance sheet as the allowances are surrendered.

RENEWABLE ENERGY CERTIFICATES

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

PROPERTY, PLANT AND EQUIPMENT

PP&E is recorded at cost and primarily represents the buildings, equipment and other facilities used to provide natural gas and electric utility services, including construction work in progress. PP&E also includes lease improvements and other equipment. Our plant costs include labor, materials and contract services and expenditures for replacement parts incurred during a major maintenance outage of a plant. In addition, the cost of utility plant includes AFUDC. 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 assets collateralized as security for certain indebtedness in Note 5.

PROPERTY, PLANT AND EQUIPMENT BY MAJOR FUNCTIONAL CATEGORY

(Dollars in millions)

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	04/17/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	December 31,		Depreciation rates for years ended December 31,		
	2019	2018	2019	2018	2017
Natural gas operations	$ 2,534	$ 2,382	2.47%	2.44%	2.40%
Electric distribution	7,985	7,462	3.94	3.91	3.92
Electric transmission(1)	6,577	6,222	2.79	2.76	2.71
Electric generation(2)	2,415	2,999	4.50	4.12	4.05
Other electric(3)	1,492	1,408	6.61	6.43	5.54
Construction work in progress(1)	1,501	1,221	NA	NA	NA
Total	$ 22,504	$ 21,694			

(1) *At December 31, 2019, includes $484 million in electric transmission assets and $13 million in construction work in progress related to SDG&E's 90% interest in the Southwest Powerlink 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. SDG&E's share of operating expenses is included in the Statement of Operations.*

(2) *Includes capital lease assets of $1.9 billion at December 31, 2018.*

(3) *Includes capital lease assets of $13 million at December 31, 2018.*

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

DEPRECIATION EXPENSE
(Dollars in millions)

	Years ended December 31,		
	2019	2018	2017
SDG&E	$ 719	$ 655	$ 593

ACCUMULATED DEPRECIATION
(Dollars in millions)

	December 31,	
	2019	2018
Accumulated depreciation:		
Electric(1)	$ 4,705	$ 4,572
Natural gas	832	794
Total	5,537	5,366

(1) *Includes accumulated depreciation for capital lease assets of $330 million at December 31, 2018. Includes $263 million at December 31, 2019 related to SDG&E's 90% interest in the Southwest Powerlink transmission line, jointly owned by SDG&E and other utilities.*

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 capitalize interest costs incurred to finance capital projects that have not commenced planned principal operations.

The table below summarizes capitalized interest and AFUDC.

CAPITALIZED FINANCING COSTS
(Dollars in millions)

	Years ended December 31,		
	2019	2018	2017
SDG&E	$ 75	$ 82	$ 85

LONG-LIVED ASSETS

We test 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 entities. 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; and
- 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 AROs 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 the asset is placed into service), and accreting the obligation until the liability is settled. We 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 AROs related to various assets, including:

- fuel and storage tanks

- natural gas transmission and distribution systems
- hazardous waste storage facilities
- asbestos-containing construction materials
- nuclear power facilities
- electric transmission and distribution systems
- energy storage systems
- power generation plants

The changes in ARO are as follows:

CHANGES IN ASSET RETIREMENT OBLIGATIONS
(Dollars in millions)

	2019	2018
Balance as of January 1	$ 872	$ 837
Accretion expense	39	39
Liabilities incurred	—	—
Deconsolidation and reclassification	—	—
Payments	(44)	(39)
Revisions	(1)	35
Balance at December 31[1]	$ 866	$ 872

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 owners and 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 (Loss) shows the changes in the components of OCI. The following table presents the changes in AOCI by component and amounts reclassified out of AOCI to net income:

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, 2016	$ (8)	$ (8)
OCI before reclassifications	(1)	(1)
Amounts reclassified from AOCI	1	1
Net OCI	—	—
Balance as of December 31, 2017	(8)	(8)
OCI before reclassifications	(6)	(6)
Amounts reclassified from AOCI	4	4
Net OCI	(2)	(2)
Balance as of December 31, 2018	(10)	(10)
Cumulative-effect adjustment from change in accounting principle	(2)	(2)
OCI before reclassifications	(5)	(5)
Amounts reclassified from AOCI	1	1
Net OCI	(4)	(4)
Balance as of December 31, 2019	$ (16)	$ (16)

(1) *All amounts are net of income tax, if subject to tax.*

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 Statement of Operations
	Years ended December 31,			
	2019	2018	2017	
Pension and other postretirement benefits[1]:				
Amortization of actuarial loss	$ —	$ 1	$ 1	Other Income, Net
Amortization of prior service cost	1	—	—	Other Income, Net
Settlement charges	—	4	—	Other Income, Net
Total before income tax	1	5	1	
	—	(1)	—	Income Tax Expense
Net of income tax	$ 1	$ 4	$ 1	
Total reclassifications for the period, net of tax	$ 1	$ 4	$ 1	

(1) *Amounts are included in the computation of net periodic benefit cost (see “Net Periodic Benefit Cost” in Note 7).*

REVENUES

See Note 3 for a description of significant accounting policies for revenues.

OPERATION AND MAINTENANCE EXPENSES

Operation and Maintenance includes O&M and general and administrative costs, consisting primarily of personnel costs, purchased materials and services, litigation expense and rent.

TRANSACTIONS WITH AFFILIATES

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

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

	December 31, 2019	December 31, 2018
Sempra Energy	$ (37)	$ (43)
SoCalGas	(10)	(6)
Various affiliates	(6)	(12)
Total due to unconsolidated affiliates – current	$ (53)	$ (61)
Income taxes due from Sempra Energy[(1)]	$ 130	$ 5

(1) SDG&E is included in the consolidated income tax return of Sempra Energy and its income tax expense is computed as an amount equal to that which would result from having always filed a separate return.

The following table summarizes revenues and cost of sales from unconsolidated affiliates.

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

	Years ended December 31, 2019	2018	2017
Revenues	$ 6	$ 5	$ 8
Cost of Sales	$ 74	$ 73	$ 71

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 effective rate plus a margin of 13 to 20 bps, 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 O&M.

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 presented net in SoCalGas' Statement 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% owned and unconsolidated JV of Sempra Mexico.

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, 2019, Sempra Energy could have received combined loans and dividends of approximately $885 million.

The payment and amount of future dividends are at the discretion of our boards 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 ratios be no lower than one percentage point below the CPUC-authorized percentage of our authorized capital structure. Our authorized percentage at December 31, 2019 is 52%.
- SDG&E has a revolving credit line that requires it to maintain a ratio of indebtedness to capitalization (as defined in the agreements) of no more than 65%, as we discuss in Note 5.

Based on these restrictions, at December 31, 2019, SDG&E's restricted net assets were $6.2 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,		
	2019	2018	2017
Allowance for equity funds used during construction	$ 56	$ 61	$ 63
Non-service component of net periodic benefit (cost) credit	(20)	(6)	4
Interest on regulatory balancing accounts, net	13	4	3
Sundry, net	(10)	(5)	(2)
Total	$ 39	$ 54	$ 68

NOTE 2. NEW ACCOUNTING STANDARDS

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

ASU 2016-02, "Leases," ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842," ASU 2018-10, "Codification Improvements to Topic 842, Leases," ASU 2018-11, "Leases (Topic 842): Targeted Improvements," ASU 2018-20, "Narrow-Scope Improvements for Lessors" and ASU 2019-01, "Leases (Topic 842): Codification Improvements" (collectively referred to as the "lease standard"): In 2016, the Financial Accounting Standards Board began issuing the first in a series of ASUs intended to increase transparency and comparability among organizations with leasing activities. The most significant provision of the lease standard is the requirement that lessees recognize operating lease ROU assets and lease liabilities on the balance sheet.

We adopted the lease standard on January 1, 2019 using the optional modified retrospective transition method to apply the new guidance as of January 1, 2019, rather than as of the earliest period presented. We elected the package of practical expedients that permits us to not reassess (a) whether a contract is or contains a lease, (b) lease classification or (c) determination of initial direct costs, which allows us to carry forward accounting conclusions under previous U.S. GAAP on contracts that commenced prior to adoption of the lease standard. We also elected the land easement practical expedient, which allows us to continue to account for pre-existing land easements under our accounting policy that existed before adoption of the lease standard. We did not elect the practical expedient to use hindsight in making judgments when determining the lease term.

The adoption of the lease standard did not change our previously reported financial statements. The adoption of the lease standard had a material impact on our balance sheet at January 1, 2019 due to the initial recognition of ROU assets and lease liabilities for operating leases. Our finance leases were already included on our balance sheet prior to adoption of the lease standard, consistent with previous U.S. GAAP for capital leases.

The following table shows the initial increase on our balance sheet at January 1, 2019 from adoption of the lease standard.

IMPACT FROM ADOPTION OF THE LEASE STANDARD *(Dollars in millions)*		
Right-of-use assets – operating leases	$	130
Other current liabilities		20
Deferred credits and other		110

We include additional disclosures about our leases in Note 13.

ASU 2016-13, "Measurement of Credit Losses on Financial Instruments": ASU 2016-13, as amended by subsequently issued ASUs, 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, including interim periods therein, with early adoption permitted for fiscal years beginning after December 15, 2018. The amendments are to be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings at the beginning of the first reporting period in the year of adoption.

On a prospective basis, the new standard will primarily apply to our accounts receivable balances, amounts due from unconsolidated affiliates and off-balance sheet financial guarantees. We will adopt the standard on January 1, 2020.

We expect no impact to SDG&E's balance sheet from adoption.

ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income": ASU 2018-02 contains amendments that allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the TCJA. Under ASU 2018-02, an entity is required to provide certain disclosures regarding stranded tax effects, including its accounting policy related to releasing the income tax effects from AOCI. The amendments in this update can be applied either as of the beginning of the period of adoption or retrospectively as of the date of enactment of the TCJA and to each period in which the effect of the TCJA is recognized. We adopted ASU 2018-02 on January 1, 2019 and reclassified the income tax effects of the TCJA from AOCI to retained earnings.

The impact from adoption of ASU 2018-02 on January 1, 2019 was an increase of $2 million to beginning Retained Earnings and Accumulated Other Comprehensive Loss.

ASU 2019-12, "Simplifying the Accounting for Income Taxes": ASU 2019-12 simplifies certain areas of accounting for income taxes. In addition to other changes, this standard amends ASC 740, "Income Taxes," as follows:

- removes the exception to the incremental approach for intraperiod tax allocation when there is a loss from continuing operations and income or a gain from other items, including discontinued operations or other comprehensive income;
- simplifies the recognition of deferred taxes related to basis differences as a result of ownership changes in investments;
- specifies an entity is not required to allocate the consolidated amount of current and deferred tax expense to a legal entity that is not subject to tax in its separate financial statements; and
- requires an entity to reflect the effect of an enacted change in tax laws or rates in the annual ETR computation in the interim period that includes the enactment date.

For public entities, ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, including interim periods therein, with early adoption permitted. The transition method related to the amendments made by ASU 2019-12 vary based on the nature of the change. We are currently evaluating our planned adoption date and the effect of the standard on our ongoing financial reporting.

NOTE 3. REVENUES

The following table disaggregates our revenues from contracts with customers by major service line and market and provides a reconciliation to total revenues by segment. The majority of our revenue is recognized over time.

DISAGGREGATED REVENUES

(Dollars in millions)

		Year ended December 31, 2019
By major service line:		
Utilities	$	4,820
Energy-related businesses		—
Revenues from contracts with customers	$	4,820
By market:		
Gas	$	587
Electric		4,233
Revenues from contracts with customers	$	4,820
Revenues from contracts with customers	$	4,820
Utilities regulatory revenues		106
Other revenues		—
Total revenues	$	4,926

		Year ended December 31, 2018
By major service line:		
Utilities	$	4,790
Energy-related businesses		—
Revenues from contracts with customers	$	4,790
By market:		
Gas	$	491
Electric		4,299
Revenues from contracts with customers	$	4,790
Revenues from contracts with customers	$	4,790
Utilities regulatory revenues		(220)
Other revenues		—
Total revenues	$	4,570

REVENUES FROM CONTRACTS WITH CUSTOMERS

Our revenues from contracts with customers are primarily related to the transmission, distribution and storage of natural gas and the generation, transmission and distribution of electricity. We assess our revenues on a contract-by-contract basis as well as a portfolio basis to determine the nature, amount, timing and uncertainty, if any, of revenues being recognized.

We generally recognize revenues when performance of the promised commodity service is provided to our customers and invoice our customers for an amount that reflects the consideration we are entitled to in exchange for those services. We consider the delivery and transmission of natural gas and electricity and providing of natural gas storage services as ongoing and integrated services. Generally, natural gas or electricity services are received and consumed by the customer simultaneously. Our performance obligations related to these services are satisfied over time and represent a series of distinct services that are substantially the same and that have the same pattern of transfer to the customers. We recognize revenue based on units delivered, as the satisfaction of our performance obligations can be directly measured by the amount of natural gas or electricity delivered to the customer. In most cases, the right to consideration from the customer directly corresponds to the value transferred to the customer and we recognize revenue in the amount that we have the right to invoice.

The payment terms in our customer contracts vary. Typically, we have an unconditional right to customer payments, which are due after the performance obligation to the customer is satisfied. The term between invoicing and when payment is due is typically between 10 and 90 days.

We exclude sales and usage-based taxes from revenues. In addition, we pay franchise fees to operate in various municipalities. We bill these franchise fees to their customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SDG&E's ability to collect from the customer, are accounted for on a gross basis and reflected in utilities revenues from contracts with customers and operating expense.

Revenues

Our revenues consist of the transmission, distribution and storage of natural gas and the generation, transmission and distribution of electricity.

Our revenues are derived from and recognized upon the delivery of natural gas or electricity services to customers. Amounts that we bill our customers are based on tariffs set by regulators within the respective state or country. For SDG&E, which follows the provisions of U.S. GAAP governing rate-regulated operations as we discuss in Note 1, amounts that we bill to customers also include adjustments for previously recognized regulatory revenues.

We recognize revenues based on regulator-approved revenue requirements, which allows the utilities to recover their reasonable operating costs and provides the opportunity to realize our authorized rates of return on our investments. While our revenues are not affected by actual sales volumes, the pattern of our revenue recognition during the year is affected by seasonality. Our authorized revenue recognition is also impacted by seasonal factors, resulting in higher earnings in the third quarter when electric loads are typically higher than in the other three quarters of the year.

SDG&E has an arrangement to provide the California ISO with the ability to control its high-voltage transmission lines for prices approved by the FERC. Revenue is recognized over time as access is provided to the California ISO.

Factors that can affect the amount, timing and uncertainty of revenues and cash flows include weather, seasonality and timing of customer billings, which may result in unbilled revenues that can vary significantly from month to month and generally approximate one-half month's deliveries.

We recognize revenues from the sale of allocated California GHG emissions allowances at quarterly auctions administered by CARB. GHG allowances are delivered to CARB in advance of the quarterly auctions, and we have the right to payment when the GHG allowances are sold at auction. GHG revenue is recognized on a point in time basis within the quarter the auction is held. We balance costs and revenues associated with the GHG program through regulatory balancing accounts.

Remaining Performance Obligations

We do not disclose information about remaining performance obligations for (a) contracts with an original expected length of one year or less, (b) variable consideration recognized at the amount at which we have the right to invoice for services performed, or (c) variable consideration allocated to wholly unsatisfied performance obligations.

For contracts greater than one year, at December 31, 2019, we expect to recognize revenue related to the fixed fee component of the consideration as shown below.

REMAINING PERFORMANCE OBLIGATIONS[1] (Dollars in millions)		
2020	$	4
2021		4
2022		4
2023		4
2024		4
Thereafter		71
Total revenues to be recognized	$	91

(1) *Excludes intercompany transactions.*

Contract Balances from Revenues from Contracts with Customers

From time to time, we receive payments in advance of satisfying the performance obligations associated with customer contracts. We defer such revenues as contract liabilities and recognize them in earnings as the performance obligations are satisfied.

Activities within SDG&E's contract liabilities are presented below. There were no contract liability activities at SDG&E in 2018.

CONTRACT LIABILITIES (Dollars in millions)		SDG&E
Opening balance, January 1, 2019	$	—
Revenue from performance obligations satisfied during reporting period		1
Payments received in advance		(92)
Balance at December 31, 2019[1]	$	(91)

(1) *Includes $4 million in Other Current Liabilities and $87 million in Deferred Credits and Other on the SDG&E Balance Sheet.*

Receivables from Revenues from Contracts with Customers

The table below shows receivable balances associated with revenues from contracts with customers on our Balance Sheet.

RECEIVABLES FROM REVENUES FROM CONTRACTS WITH CUSTOMERS

(Dollars in millions)

	December 31, 2019	December 31, 2018
Accounts receivable – trade, net	$ 398	$ 368
Accounts receivable – other, net	5	6
Due from unconsolidated affiliates – current[1]	2	3
Total	$ 405	$ 377

(1) *Amount is presented net of amounts due to unconsolidated affiliates on the Balance Sheet, when right of offset exists.*

REVENUES FROM SOURCES OTHER THAN CONTRACTS WITH CUSTOMERS

Certain of our revenues are derived from sources other than contracts with customers and are accounted for under other accounting standards outside the scope of ASC 606.

Regulatory Revenues

Alternative Revenue Programs

We recognize revenues from alternative revenue programs when the regulator-specified conditions for recognition have been met and adjust these revenues as they are recovered or refunded through future utility service.

Decoupled revenues. As discussed earlier, the regulatory framework requires SDG&E to recover authorized revenue based on estimated annual demand forecasts approved in regular proceedings before the CPUC. However, actual demand for natural gas and electricity will generally vary from CPUC-approved forecasted demand due to the impacts from weather volatility, energy efficiency programs, rooftop solar and other factors affecting consumption. The CPUC regulatory framework provides for the SDG&E to use a "decoupling" mechanism, which allows SDG&E to record revenue shortfalls or excess revenues resulting from any difference between actual and forecasted demand to be recovered or refunded in authorized revenue in a subsequent period based on the nature of the account.

Incentive mechanisms. The CPUC applies performance-based measures and incentive mechanisms to all California IOUs, under which the SDG&E has earnings potential above authorized base margins if we achieve or exceed specific performance and operating goals. Generally, for performance-based awards, if performance is above or below specific benchmarks, we are eligible for financial awards or subject to financial penalties.

Incentive awards are included in revenues when we receive required CPUC approval of the award, the timing of which may not be consistent from year to year. We would record penalties for results below the specified benchmarks against revenues when we believe it is probable that the CPUC would assess a penalty.

Other Cost-Based Regulatory Recovery

The CPUC and the FERC authorize SDG&E to collect revenue requirements for operating costs and capital related costs (such as depreciation, taxes and return on rate base) from customers, including:

- costs to purchase natural gas and electricity;
- costs associated with administering public purpose, demand response, and customer energy efficiency programs;
- other programmatic activities, such as gas distribution, gas transmission, gas storage integrity management and wildfire mitigation;

and

- costs associated with third party liability insurance premiums.

Authorized costs are recovered as the commodity or service is delivered. To the extent authorized amounts collected vary from actual costs, the differences are generally recovered or refunded within a subsequent period based on the nature of the balancing account mechanism. In general, the revenue recognition criteria for balanced costs billed to customers are met at the time the costs are incurred. Because these costs are substantially recovered in rates through a balancing account mechanism, changes in these costs are reflected as changes in revenues. The CPUC and the FERC may impose various review procedures before authorizing recovery or refund for programs authorized, including limitations on the total cost of the program, revenue requirement limits or reviews of costs for reasonableness. These procedures could result in disallowances of recovery from ratepayers.

We discuss balancing accounts and their effects further in Note 4.

NOTE 4. REGULATORY MATTERS

REGULATORY ASSETS AND LIABILITIES

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

REGULATORY ASSETS (LIABILITIES)
(Dollars in millions)

	December 31, 2019	December 31, 2018
Fixed-price contracts and other derivatives	$ 8	$ (150)
Deferred income taxes refundable in rates	(108)	(236)
Pension and other postretirement benefit plan obligations	103	186
Removal obligations	(2,056)	(1,848)
Environmental costs	45	28
Sunrise Powerlink fire mitigation	121	120
Regulatory balancing accounts(1)(2)		
Commodity – electric	102	(8)
Gas transportation	22	45
Safety and reliability	77	70
Public purpose programs	(124)	(62)
2019 GRC retroactive impacts	111	—
Other balancing accounts	106	145
Other regulatory liabilities, net(2)	(153)	(170)
Total	$ (1,746)	$ (1,880)

(1) *At December 31, 2019 and 2018, the noncurrent portion of regulatory balancing accounts – net undercollected was $108 million and $78 million, respectively.*

(2) *Includes regulatory assets earning a return.*

In the table above:

- Regulatory 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.
- Deferred income taxes refundable/recoverable in rates are based on current regulatory ratemaking and income tax laws. SDG&E expects to refund/recover net regulatory liabilities/assets related to deferred income taxes over the lives of the assets that give rise to the related accumulated deferred income tax balances. Regulatory assets and liabilities include certain income tax benefits and expenses associated with flow-through items, which we discuss in Note 6.
- 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.

- The regulatory asset related to employee benefit costs represents our liability associated with long-term disability insurance that will be recovered from customers in future rates as expenditures are made.
- Regulatory liabilities from removal obligations represent cumulative amounts collected in rates for future asset removal costs in excess of cumulative amounts incurred (or paid).
- 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.
- 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 50-year period.
- Over- and undercollected regulatory balancing accounts reflect the difference between customer billings and recorded or CPUC-authorized costs, including commodity costs. Depreciation and return on rate base may also be included in certain accounts. Amounts in the balancing accounts are recoverable (receivable) or refundable (payable) in future rates, subject to CPUC approval.

Amortization expense on regulatory assets for the years ended December 31, 2019, 2018 and 2017 was $3 million, $2 million and $49 million, respectively, at SDG&E.

CALIFORNIA UTILITIES

CPUC General Rate Case

The CPUC uses GRC proceedings to set rates designed to allow SDG&E to recover their reasonable operating costs and to provide the opportunity to realize their authorized rates of return on their investments.

2019 General Rate Case

On September 26, 2019, the CPUC issued a final decision in the 2019 GRC approving SDG&E's test year revenues for 2019 and attrition year adjustments for 2020 and 2021. This is the first GRC that includes revenues authorized for risk assessment mitigation phase activities.

The 2019 GRC FD adopts a test year 2019 revenue requirement of $1,990 million for SDG&E's combined operations ($1,590 million for its electric operations and $400 million for its natural gas operations), which is $213 million lower than the $2,203 million that SDG&E had requested in its updated application. SDG&E's adopted 2019 revenue requirement represents an increase of $107 million (5.70%) over its authorized 2018 revenue requirement.

The increases include separately authorized components for O&M and capital-related costs, as follows:

AUTHORIZED REVENUE REQUIREMENT INCREASES FOR 2020 AND 2021

(Dollars in millions)

	2020 increase from 2019		2021 increase from 2020	
	Revenue increase	Percent increase	Revenue increase	Percent increase
O&M	$ 20	2.64%	$ 19	2.47%
Capital-related costs	114	9.74	83	6.47
Total increase	$ 134	6.74	$ 102	4.83

The adopted revenue requirements associated with the period from January 1, 2019 through December 31, 2019 are being recovered in rates over a 24-month period beginning in January 2020. At December 31, 2019, SDG&E recorded an associated regulatory asset of $111 million, with $56 million as noncurrent.

In January 2020, the CPUC issued a final decision implementing a four-year GRC cycle for California IOUs. SDG&E was directed to file a petition for modification to revise its 2019 GRC to add two additional attrition years, resulting in a transitional five-year GRC period (2019-2023).

The 2019 GRC FD approves for SDG&E the establishment of two-way liability insurance premium balancing accounts, including wildfire insurance premium costs based on a specific level of coverage. The 2019 GRC FD also permits SDG&E to seek recovery of additional liability insurance coverage.

Pursuant to the 2016 GRC FD, SDG&E established a two-way income tax expense memorandum account to track, among other items, certain revenue variances resulting from certain differences between the income tax expense forecasted in the GRC and the income tax expense incurred from 2016 through 2018. SDG&E recorded regulatory liabilities associated with the 2016 through 2018 tracked forecasting differences of $86 million. The 2019 GRC FD clarifies that forecasting differences, which we previously included in this tracked activity, are not subject to tracking in the income tax expense memorandum account. Final resolution of the scope of the two-way income tax expense memorandum account for the 2016 through 2018 period is pending at the CPUC and could impact the disposition of these regulatory liabilities. We expect resolution in the first half of 2020

The 2016 GRC FD revenue requirement was authorized using a federal income tax rate of 35%. As a result of TCJA, the federal income tax rate became 21% effective January 1, 2018. Since SDG&E continued to collect authorized revenues based on a 35% tax rate, SDG&E recorded regulatory liabilities of $88 million. Pursuant to the 2019 GRC FD, SDG&E is refunding the regulatory balances over a 24-month period starting January 2020. SDG&E also recorded a $66 million regulatory liability at December 31, 2019, relating to its FERC jurisdictional rates, which it began refunding in June 2019.

CPUC Cost of Capital

In April 2019, SDG&E filed an application with the CPUC to update its cost of capital effective January 1, 2020. SDG&E proposed to adjust its authorized capital structure by increasing the amount of its common equity from 52% to 56%. SDG&E also proposed to increase its authorized ROE from 10.2% to 14.3% (with the aggregate ROE proposal including a quantified premium for wildfire liability risk), and to increase its authorized return on rate base from 7.55% to 10.03%. In August 2019, SDG&E filed supplemental testimony to update its ROE request from 10.2% to 12.38% to reflect the impacts of the Wildfire Legislation, including a revised premium for wildfire liability risk, and its authorized return on rate base from 7.55% to 8.95%.

In December 2019, the CPUC approved the cost of capital and rate structure (shown in the table below) for SDG&E that are effective January 1, 2020 and will remain in effect through December 31, 2022. SDG&E did not propose a 2020 cost of preferred equity in this proceeding. In January 2020, SDG&E filed an advice letter to continue the cost of preferred equity for test year 2020 at 6.22%, which recieved approval in March of 2020.

CPUC AUTHORIZED COST OF CAPITAL AND RATE STRUCTURE

	Authorized weighting		Return on rate base		Weighted return on rate base	
Long-Term Debt	45.25	%	4.59	%	2.08	%
Preferred Stock	2.75		6.22		0.17	
Common Equity	52.00		10.20		5.30	
	100.00	%			7.55	%

The CCM was reauthorized in the 2020 cost of capital proceeding to continue through 2022. The CCM benchmark rate for the 2020 cost of capital is the average monthly utility bond index, as published by Moody’s, for the 12-month period from October 2018 through September 2019. SDG&E’s CCM benchmark rate is 4.491%, based on Moody’s Baa- utility bond index. The index applicable to SDG&E is based on its credit rating.

The CCM benchmark rate for SDG&E is the basis of comparison to determine if future measurement periods “trigger” the CCM. The 12 months ending September 2020 shall be the first “CCM Period” to determine if there has been a trigger at SDG&E. The trigger occurs if the change in the applicable average Moody’s utility bond index relative to the CCM benchmark is larger than plus or minus 1.000%. Accordingly, if a change of more than plus or minus 1.000% occurs, SDG&E’s authorized ROE would be adjusted, upward or downward, by one half of the difference between the CCM benchmark and the 12-month average determined during the CCM Period. In addition, the authorized recovery rate for the SDGE’s cost of debt and preferred stock would be adjusted to its actual weighted-average cost, with no change to the authorized capital structure. In the event of a CCM trigger, the CCM benchmark is also reestablished. These adjustments would become effective in authorized rates on January 1 of the year following the CCM trigger.

SDG&E

FERC Rate Matters and Cost of Capital

SDG&E files separately with the FERC for its authorized ROE on FERC-regulated electric transmission operations and assets.

SDG&E’s current estimated FERC return on rate base under the TO4 formula rate request filing is 7.51% based on its capital structure as follows:

FERC–AUTHORIZED COST OF CAPITAL AND RATE STRUCTURE

	Weighting	Return on rate base	Weighted return on rate base
Long-Term Debt	43.44 %	4.21 %	1.83 %
Common Equity	56.56	10.05	5.68
	100.00 %		7.51 %

FERC Formulaic Rate Filing

In October 2018, SDG&E submitted its TO5 filing to the FERC proposing, among other items, an increase to SDG&E's current authorized FERC ROE from 10.05% to 11.20%. This proceeding establishes the transmission revenue requirement, including rate of return, for SDG&E's FERC-regulated electric transmission operations and assets. On December 31, 2018, the FERC issued its order accepting and suspending SDG&E's TO5 filing for five months, during which the existing TO4 rates remained in effect, and established hearing and settlement procedures. The suspension period ended on June 1, 2019, when the proposed TO5 rates took effect, subject to refund and the outcome of the rate filing. As a result, until a new ROE is authorized, the current ROE of 10.05% is the basis of SDG&E's FERC-related revenue recognition.

In October 2019, SDG&E and all settling parties reached an agreement on all issues set for hearing in the proceeding. The agreement provides for a ROE of 10.60%, consisting of a base ROE of 10.10% plus an additional 50 bps for participation in the California ISO. SDG&E will refund the California ISO additional 50 bps of ROE as of the refund effective date (June 1, 2019) in this proceeding if the FERC issues an order ruling that California IOUs are no longer eligible for the additional California ISO ROE. The agreement also includes the collection of additional FERC revenues of $17 million to conclude a rate base matter, net of certain refunds to be paid to CPUC-jurisdictional customers. We received a FERC order approving the settlement terms in March 2020.

SDG&E expects to record the cumulative earnings effect of retroactive application to June 1, 2019 for any difference between the current ROE and the approved ROE in Q1 of 2020.

NOTE 5. DEBT AND CREDIT FACILITIES

LINE OF CREDIT

Committed Line of Credit

At December 31, 2019, SDG&E had an aggregate of $1.5 billion in committed line of credit, which provide liquidity and support commercial paper.

COMMITTED LINE OF CREDIT

(Dollars in millions)

	At December 31, 2019		
	Total facility	Commercial paper outstanding(1)	Available unused credit
SDG&E(2)(3)	1,500	(80)	1,420

(1) Because the commercial paper programs are supported by the line, we reflect the amount of commercial paper outstanding as a reduction to the available unused credit.

(2) Commercial paper outstanding is before reductions of unamortized discount of negligible amounts at SDG&E.

(3) The facility also provides for issuance of $100 million of letters of credit on behalf of the SDG&E with the amount of borrowings otherwise available under the facility reduced by the amount of outstanding letters of credit. Subject to obtaining commitments from existing or new lenders and satisfaction of other specified conditions, SDG&E has the right to increase the letter of credit commitment up to $250 million. No letters of credit were outstanding at December 31, 2019.

The principal terms of the committed line of credit in the table above include the following:

▪It is a 5-year syndicated revolving credit agreement expiring in May 2024.

▪JPMorgan Chase Bank, N.A. serves as administrative agent for the SDG&E facility.

▪Each facility has a syndicate of 23 lenders. No single lender has greater than a 6% share in any facility.

▪Borrowings bear interest at benchmark rates plus a margin that varies with SDG&E's credit rating in the case of SDG&E's line of credit.

▪SDG&E must maintain a ratio of indebtedness to total capitalization (as defined in the applicable credit facility) of no more than 65% at the end of each quarter. At December 31, 2019, SDG&E was in compliance with this ratio and all other financial covenants under its respective credit facility.

WEIGHTED-AVERAGE INTEREST RATES

The weighted-average interest rates on the total short-term debt at December 31, 2019 and 2018 were as follows:

WEIGHTED-AVERAGE INTEREST RATES		
	December 31,	
	2019	2018
SDG&E	1.97%	2.97%

LONG-TERM DEBT

The following table shows the detail and maturities of long-term debt outstanding:

LONG-TERM DEBT AND FINANCE LEASES
(Dollars in millions)

	December 31, 2019	December 31, 2018
First mortgage bonds (collateralized by plant assets):		
3% August 15, 2021	$ 350	$ 350
1.914% payable 2015 through February 2022	89	125
3.6% September 1, 2023	450	450
2.5% May 15, 2026	500	500
6% June 1, 2026	250	250
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
3.75% June 1, 2047	400	400
4.15% May 15, 2048	400	400
4.1% June 15, 2049	400	—
	5,140	4,776
Finance lease obligations:		
Purchased-power contracts	1,255	1,583
Other	15	2
	1,270	1,585
	6,410	6,361
Current portion of long-term debt	(56)	(366)
Unamortized discount on long-term debt	(12)	(12)
Unamortized debt issuance costs	(36)	(35)
Total	6,306	5,948

MATURITIES OF LONG-TERM DEBT[1] *(Dollars in millions)*		
2020	$	36
2021		386
2022		18
2023		450
2024		—
Thereafter		4,250
Total	$	5,140

(1) *Excludes finance lease obligations, discounts, 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, 2019 is callable subject to premiums:

CALLABLE LONG-TERM DEBT *(Dollars in millions)*		
Not subject to make-whole provisions	$	251
Subject to make-whole provisions		4,889

First Mortgage Bonds

We issue first mortgage bonds secured by a lien on utility plant assets. We may issue additional first mortgage bonds if in compliance with the provisions of our bond agreement (indenture). The indenture requires, 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 additional first mortgage bonds of $6.4 billion at SDG&E at December 31, 2019.

In May 2019, SDG&E issued $400 million of 4.1% first mortgage bonds maturing in 2049. We received proceeds of $396 million (net of debt discount, underwriting discounts and debt issuance costs of $4 million). SDG&E used the proceeds from the offering to repay outstanding commercial paper and for other general corporate purposes.

NOTE 6. INCOME TAXES

We provide our calculations of ETRs in the following table.

INCOME TAX EXPENSE (BENEFIT) AND EFFECTIVE INCOME TAX RATES
(Dollars in millions)

	Years ended December 31,		
	2019	2018	2017
Income tax expense	$ 171	$ 173	$ 155
Income before income taxes	$ 938	$ 842	$ 562
Effective income tax rate	18%	21 %	28%

For SDG&E, 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 ETR. As a result, changes in the relative size of these items compared to pretax income, from period to period, can cause variations in the ETR. 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, which is non-taxable
- 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

We present in the table below reconciliations of net U.S. statutory federal income tax rates to our ETRs.

RECONCILIATION OF FEDERAL INCOME TAX RATES TO EFFECTIVE INCOME TAX RATES

	Years ended December 31,		
	2019	2018	2017
U.S. federal statutory income tax rate	21%	21 %	35%
State income taxes, net of federal income tax benefit	6	5	3
Depreciation	3	3	7
Effects of the TCJA	—	—	5
Resolution of prior years' income tax items	—	—	(4)
Allowance for equity funds used during construction	(1)	(2)	(4)
Amortization of excess deferred income taxes	(1)	(1)	—
Repairs expenditures	(3)	(3)	(8)
Self-developed software expenditures	(3)	(2)	(6)
Excess deferred income taxes outside of ratemaking	(3)	—	—
Other, net	(1)	—	—
Effective income tax rate	18%	21 %	28%

In December 2017, the TCJA was signed into law. This legislation significantly changed the IRC. The TCJA reduced the U.S. statutory corporate income tax rate from 35% to 21%, effective January 1, 2018. Deferred income tax assets and liabilities, including NOLs, were remeasured at the income tax rate expected to apply when those temporary differences reverse. The effects of the change to the income tax rate were recognized in the period when the change was enacted. This remeasurement resulted in significant reductions in deferred income tax balances at SDG&E in 2017.

The remeasurement of deferred income tax balance at SDG&E resulted in excess deferred income taxes that previously have been collected from ratepayers at the higher rate. As we discuss in Note 4, these excess deferred income taxes have been recorded as regulatory liabilities and will generally be refunded to ratepayers in accordance with the IRC's normalization provisions and as determined by the CPUC and the FERC. In a January 2019 decision, the CPUC directed certain excess deferred income tax balances generated by activities outside of ratemaking be allocated to shareholders rather than ratepayers. As a result, SDG&E recorded income tax benefits of $31 million from the release of a portion of the regulatory liability established in connection with 2017 tax reform for excess deferred income tax balances.

We recorded the effects of the TCJA in 2017 using our best estimates and the information available to us through the date those financial statements were issued. In 2018, we adjusted our 2017 provisional estimates and completed our accounting for the income tax effects of the TCJA.

The table below summarizes the effects of the TCJA in 2018 and 2017:

EFFECTS OF THE TAX CUTS AND JOBS ACT OF 2017 *(Dollars in millions)*		
2018:		
Balance Sheet:		
Increase (decrease) in net deferred income tax liabilities due to remeasurement	$	(38)
Increase (decrease) in net regulatory liabilities from remeasurement of deferred income tax assets and liabilities	$	38
2017:		
Balance Sheet:		
Decrease in net deferred income tax liabilities due to remeasurement	$	(1,400)
Increase in net regulatory liabilities from remeasurement of deferred income tax assets and liabilities	$	1,428
Statement of Operations:		
Income tax expense related to remeasurement of deferred income tax assets and liabilities	$	28
Total increase in income tax expense	$	28

The table below summarizes the effects of the TCJA at December 31, 2017 by FERC account and jurisdiction:

TCJA REMEASUREMENT – REDUCTION TO DEFERRED INCOME TAX BALANCES
(Dollars in millions)

	FERC ACs 182.3/254	FERC AC 190(1)	FERC AC 282	FERC AC 283(2)	Total Deferred	FERC AC 410 (Exp)
FERC	$ 599	$ 5	$ (421)	$ (183)	$ (599)	
CPUC	$ 829	$ 6	$ (474)	$ (361)	$ (829)	
Shareholder		$ 2	$ 26		$ 28	$ (28)
Total	$ 1,428	$ 13	$ (869)	$ (544)	$ (1,400)	$ (28)

(1) Since account 190 is an asset, the decrease in this table is shown as positive. Does not include the net operating loss deferred tax asset related to FERC Transmission.
(2) Account 283 includes approximately $500 million of gross-up required under ASC 740 on flow-through deferred taxes and gross-up on excess deferred taxes.

In the first quarter of 2018, there was a true up to the remeasurement in the amount of $38M primarily related to ASC 740, *Income taxes*, gross-up on flow-through deferred taxes. This resulted in additional reduction of deferred tax liabilities and an increase in net regulatory liabilities. In the first quarter of 2019, certain excess deferred taxes in the amount of $31M, which had initially been recorded as regulatory liabilities as part of the TCJA remeasurement, were reclassed to Shareholder, since these items were not related to plant in service nor were they part of the reduction to rate base for Accumulated Deferred Income Taxes.

The amount of excess deferred income taxes related to plant in service (excluding gross-up) that is considered protected and unprotected as of December 31, 2019, 2018 and 2017 is reflected below:

TOTAL COMPANY EXCESS DEFERRED INCOME TAXES FOR PLANT IN SERVICE (1)
(Dollars in millions)

	Years ended December 31, 2019	2018	2017
FERC - Protected	$ 380	$ 382	$ 384
CPUC - Protected	$ 457	$ 463	$ 469
FERC - Unprotected	$ 1	$ 3	$ 6
CPUC - Unprotected	$ (118)	$ (120)	$ (122)
Total	$ 720	$ 728	$ 737

For plant in service, excess deferred income taxes will be amortized over the book life of the underlying property. SDG&E computes the annual amortization of excess deferred taxes using the Average Rate Assumption Method (ARAM). As of December 31, 2019, SDG&E has not received a regulatory order from the FERC regarding how customer rates should be reduced for excess deferred income taxes. During 2019, SDG&E received a final decision from the CPUC in its general rate case allowing it to track differences between using ARAM and straight-line amortization over a six year period for certain unprotected items. The CPUC decision also permitted SDG&E to track differences related to the inclusion of new cost of removal accruals in the ARAM calculation. Future potential regulatory orders and IRS guidance could impact the classification of protected and unprotected amounts indicated above as well as the inclusion of new cost of removal accruals in the ARAM calculation.

Under ARAM, SDG&E reduced its regulatory liability related to excess deferred income taxes by $8 million and $9 million in 2019 and 2018 respectively, excluding gross-up. The reduction in the excess deferred income tax regulatory liability (FERC AC 254) was offset against deferred income taxes (FERC AC 411.1). This adjustment has been reflected in the following FERC accounts as of December 31, 2019 and 2018:

ARAM - REGULATORY LIABILITY / DEFERRED INCOME TAXES
(Dollars in millions)

	Years ended December 31, 2019	2018	Amortization Period
FERC ACs 254/411.1			
FERC - Protected	$ 2	$ 2	Book Depreciation Life
CPUC - Protected	$ 6	$ 6	Book Depreciation Life
FERC - Unprotected	$ 2	$ 3	Book Depreciation Life
CPUC - Unprotected	$ (2)	$ (2)	Book Depreciation Life
Total	$ 8	$ 9	

The components of income tax expense are as follows.

INCOME TAX EXPENSE (BENEFIT)
(Dollars in millions)

	Years ended December 31,		
	2019	2018	2017
Current:			
U.S. federal	$ 35	$ 104	$ 100
U.S. state	31	30	65
Total	66	134	165
Deferred:			
U.S. federal	75	17	29
U.S. state	32	24	(41)
Total	107	41	(12)
Deferred investment tax credits	(2)	(2)	2
Total income tax expense	$ 171	$ 173	$ 155

The table below presents the components of deferred income taxes:

DEFERRED INCOME TAXES
(Dollars in millions)

	December 31, 2019	December 31, 2018
Deferred income tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 1,735	$ 1,578
Regulatory balancing accounts	141	84
Right-of-use assets – operating leases	32	—
Property taxes	30	29
Other	14	10
Total deferred income tax liabilities	1,952	1,701
Deferred income tax assets:		
Tax credits	6	6
Postretirement benefits	37	58
Compensation-related items	6	5
Operating lease liabilities	32	—
State income taxes	7	6
Accrued expenses not yet deductible	9	4
Other	7	6
Total deferred income tax assets	104	85
Net deferred income tax liability	$ 1,848	$ 1,616

Following is a reconciliation of the changes in unrecognized income tax benefits and the potential effect on our ETR for the years ended December 31:

RECONCILIATION OF UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	2019	2018	2017
Balance at January 1	$ 11	$ 10	$ 22
Increase in prior period tax positions	1	1	9
Decrease in prior period tax positions	—	—	(11)
Settlements with taxing authorities	—	—	(10)
Balance at December 31	$ 12	$ 11	$ 10
Of December 31 balance, amounts related to tax positions that if recognized in future years would			
decrease the effective tax rate(1)	$ (9)	$ (9)	$ (7)
increase the effective tax rate(1)	1	1	1

(1) *Includes temporary book and tax differences that are treated as flow-through for ratemaking purposes, as discussed above.*

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,		
	2019	2018	2017
Potential resolution of audit issues with various U.S. federal, state and local taxing authorities	$ (6)	$ (6)	$ (6)

SDG&E accrued negligible amounts for interest expense and penalties at December 31, 2019 and 2018 on the Balance Sheet, and recorded negligible amounts of interest expense and penalties in each of 2019, 2018 and 2017 on the Statement of Operations.

INCOME TAX AUDITS

We are subject to U.S. federal income tax and state income tax. We remain subject to examination for U.S. federal tax years after 2015 and state tax years after 2010.

NOTE 7. EMPLOYEE BENEFIT PLANS

For our employee benefit plans, we:

- recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status in the balance sheet;

- measure a plan's assets and its obligations that determine its funded status as of the end of the fiscal year; and
- recognize changes in the funded status of pension and PBOP plans in the year in which the changes occur. Generally, those changes are reported in OCI and as a separate component of shareholders' equity.

The detailed information presented below covers the employee benefit plans of primarily Sempra Energy and its consolidated 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 PBOP plans, including separate plans for SDG&E, 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 $488 million and $416 million at December 31, 2019 and 2018, respectively.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Benefit Plan Amendments Affecting 2019 and 2018

In 2019 and 2018, certain executive participants in a company nonqualified pension plan became eligible in this same plan for Supplemental Executive Retirement Plan benefits. This was treated as a plan amendment and increased the recorded pension liability by $3 million and $8 million in 2019 and 2018, respectively.

Settlement Accounting for Lump Sum Payments

When applicable, we record settlement charges for lump sum payments from our nonqualified pension plans that are in excess of the respective plan's service cost plus interest cost. SDG&E recorded settlement charges of $4 million in 2018.

Sale of Qualified Pension Plan Annuity Contracts

In March 2018, an insurance company purchased annuities for certain current annuitants in the SDG&E qualified pension plans and assumed the obligation for payment of these annuities. At SDG&E in the first quarter of 2018, the liability transferred for these annuities, plus the total year-to-date lump-sum payments, exceeded the settlement threshold, which triggered settlement accounting. This resulted in a reduction of the recorded pension liability and pension plan assets of $132 million. This also resulted in settlement charges in net periodic benefit cost of $22 million. The settlement charges were recorded as regulatory assets on the Balance Sheet.

Special Termination Benefits Affecting 2018 and 2017

In 2018, certain nonrepresented, and in 2017, certain represented, 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 these years 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 PBOP and net periodic benefit cost of $3 million in 2018.

Benefit Obligations and Assets

The following table provides a reconciliation of the changes in the plans' projected benefit obligations and the fair value of assets during 2019 and 2018, and a statement of the funded status at December 31, 2019 and 2018:

PROJECTED BENEFIT OBLIGATION, FAIR VALUE OF ASSETS AND FUNDED STATUS
(Dollars in millions)

	Pension benefits		Other postretirement benefits	
	2019	2018	2019	2018
CHANGE IN PROJECTED BENEFIT OBLIGATION				
Net obligation at January 1	$ 814	$ 971	$ 170	$ 185
Service cost	30	30	4	5
Interest cost	34	35	7	7
Contributions from plan participants	—	—	7	8
Actuarial loss (gain)	61	(63)	7	(17)
Plan amendments	3	8	—	—
Benefit payments	(18)	(22)	(18)	(21)
Special termination benefits	—	—	—	3
Settlements	(39)	(145)	—	—
Transfer of liability from other plans	10	—	—	—
Net obligation at December 31	895	814	177	170
CHANGE IN PLAN ASSETS				
Fair value of plan assets at January 1	600	776	172	195
Actual return on plan assets	135	(56)	36	(12)
Employer contributions	52	47	—	2
Contributions from plan participants	—	—	7	8
Benefit payments	(18)	(22)	(18)	(21)
Settlements	(39)	(145)	—	—
Transfer of assets from other plans	9	—	—	—
Fair value of plan assets at December 31	739	600	197	172
Funded status at December 31	$ (156)	$ (214)	$ 20	$ 2
Net recorded (liability) asset at December 31	$ (156)	$ (214)	$ 20	$ 2

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 2019, 2018 and 2017, the Society of Actuaries released updated mortality improvement projection scales, reflecting changes to projected observed longevity improvements in its mortality tables. We have incorporated these assumptions, adjusted for SDG&E’s actual mortality experience, in our calculations for each of those years. Actuarial losses in pension plans in 2019 were driven primarily by a decrease in discount rates and updated census data at SDG&E and a decrease in the lump-sum conversion rate at SDG&E. These actuarial losses were partially offset by actuarial gains at SDG&E due to a decrease in the interest crediting rate for the cash balance plans. Actuarial losses in PBOP plans in 2019 were driven primarily by a decrease in discount rates at SDG&E.

Net Assets and Liabilities

The assets and liabilities of the pension and PBOP 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% corridor accounting method. Under the corridor accounting method, if as of the beginning of a year unrecognized net gain or loss exceeds 10% 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 asset smoothing and 10% corridor accounting methods help mitigate volatility of net periodic benefit 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 AOCI 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 decisions by regulatory agencies.

We record annual pension and other postretirement net periodic benefit costs equal to the contributions to their qualified plans as authorized by the CPUC. The annual contributions to the pension plans are the greater of:

- a minimum required funding amount as required by the IRS;
- the amount required to maintain an 85% Adjusted Funding Target Attainment Percentage as defined by the Pension Protection Act of 2006, as amended; or
- beginning January 1, 2019 and for the duration of the 2019 GRC cycle, a fixed amount equal to the estimated annual service cost as defined by U.S. GAAP plus one year of a 14-year amortization of the unfunded projected benefit obligation of the pension plan as of January 1, 2019, and limited to an annual amount that keeps the fair value of the pension plan assets from exceeding 110% of the pension benefit obligation of the plan.

The annual contributions to PBOP 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 PBOP 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) asset is included in the following categories on the Balance Sheet at December 31:

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

	Pension benefits		Other postretirement benefits	
	2019	2018	2019	2018
Noncurrent assets	$ —	$ —	$ 20	$ 2
Current liabilities	(3)	(2)	—	—
Noncurrent liabilities	(153)	(212)	—	—
Net recorded (liability) asset	$ (156)	$ (214)	$ 20	$ 2

Amounts recorded in AOCI at December 31, 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	
	2019	2018
Net actuarial loss	$ (9)	$ (4)
Prior service cost	(7)	(6)
Total	$ (16)	$ (10)

SDG&E has a 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)

	2019	2018
Projected benefit obligation	$ 861	$ 788
Accumulated benefit obligation	818	762
Fair value of plan assets	739	600

We also have unfunded pension plans at SDG&E. The following table shows the obligations of unfunded pension plans at December 31:

OBLIGATIONS OF UNFUNDED PENSION PLANS

(Dollars in millions)		2019		2018
Projected benefit obligation	$	34	$	26
Accumulated benefit obligation		27		19

SDG&E has a funded other postretirement benefit plan.

Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost and pretax amounts recognized in OCI for the years ended December 31:

NET PERIODIC BENEFIT COST AND AMOUNTS RECOGNIZED IN OCI
(Dollars in millions)

	Pension benefits			Other postretirement benefits		
	2019	2018	2017	2019	2018	2017
NET PERIODIC BENEFIT COST						
Service cost	$ 30	$ 30	$ 29	$ 4	$ 5	$ 5
Interest cost	34	35	38	7	7	8
Expected return on assets	(38)	(47)	(47)	(11)	(13)	(11)
Amortization of:						
Prior service cost	3	2	1	2	3	3
Actuarial loss (gain)	11	1	9	(2)	(3)	—
Settlement charges	—	26	—	—	—	—
Special termination benefits	—	—	—	—	3	—
Net periodic benefit cost	40	47	30	—	2	5
Regulatory adjustment	14	(8)	(8)	—	—	—
Total expense recognized	54	39	22	—	2	5
CHANGES IN PLAN ASSETS AND BENEFIT OBLIGATIONS RECOGNIZED IN OCI						
Net loss (gain)	5	(1)	2	—	—	—
Prior service cost	2	8	—	—	—	—
Amortization of actuarial loss	—	(1)	(1)	—	—	—
Amortization of prior service cost	(1)	—	—	—	—	—
Settlements	—	(4)	—	—	—	—
Total recognized in OCI	6	2	1	—	—	—
Total recognized in net periodic benefit cost and OCI	$ 60	$ 41	$ 23	$ —	$ 2	$ 5

Assumptions for Pension and Other Postretirement Benefit Plans

Benefit Obligation and Net Periodic Benefit Cost

We develop the discount rate assumptions using a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flows to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of corporate bonds with a Bloomberg Composite of AA or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plans' projected benefit payments discounted at this rate with the market value of the bonds selected.

Long-term 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.

Interest crediting rate is based on an average 30-year Treasury bond from the month of November of the preceding year.

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	
	2019	2018	2019	2018
Discount rate	3.44%	4.29%	3.55%	4.30%
Interest crediting rate[(1)(2)]	2.28	3.36	2.28	3.36
Rate of compensation increase	2.70-10.00	2.00-10.00	2.70-10.00	2.00-10.00

(1) Interest crediting rate for pension benefits applies only to funded cash balance plans.

(2) Interest crediting rate for other postretirement benefits applies only to interest bearing health retirement accounts.

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

	Pension benefits			Other postretirement benefits		
	2019	2018	2017	2019	2018	2017
Discount rate	4.29%	3.64%	4.08%	4.30%	3.65%	4.15%
Expected return on plan assets	7.00	7.00	7.00	6.92	6.94	6.91
Interest crediting rate[(1)(2)]	3.36	2.80	2.86	3.36	2.80	2.86
Rate of compensation increase	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00

(1) Interest crediting rate for pension benefits applies only to funded cash balance plans.

(2) Interest crediting rate for other postretirement benefits applies only to interest bearing health retirement accounts.

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		
	2019	2018	2017	2019	2018	2017
Health care cost trend rate assumed for next year	6.25%	6.50%	7.00%	4.75%	4.75%	5.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	4.75%	4.75%	5.00%	4.50%	4.50%	4.50%
Year the rate reaches the ultimate trend	2025	2025	2022	2022	2022	2022

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 PBOP plans. We maintain additional trusts, as we discuss below, for certain of the SDG&E's PBOP 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:

- 35% domestic equity
- 24% international equity
- 18% long credit
- 8% ultra-long duration government securities
- 5% global real estate investment trusts
- 5% return-seeking credit
- 5% 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

This allocation results in a 74% target allocation to return-seeking assets and a 26% target allocation to risk-mitigating assets. We maintain asset 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 PBOP 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% 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 5% and 9% on return-seeking assets and between 1% and 4% 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 PBOP plans are funded by cash contributions from SDG&E and its current retirees. The assets of these plans are placed into the pension master trust and other Voluntary Employee Beneficiary Association trusts. Certain assets of SDG&E's PBOP plans are held in the pension master trust, which invests a portion of the assets in completion portfolios that aim to reduce interest rate risk, thereby resulting in an overall target allocation of 38% to return-seeking assets and 62% to risk-mitigating assets for these well-funded plans. SDG&E's assets held in other Voluntary Employee Beneficiary Association trusts are invested in accordance with a de-risking glidepath that reduces the assets' exposure to risk as the trusts become better funded. These specific allocations are 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 investments in the trusts for SDG&E's PBOP plans based on the fair value hierarchy, except for certain investments measured at 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 flow 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. Where the value is a quoted price in an active market, the investment is classified within Level 1 of the fair value hierarchy. Investments in certain fixed income securities are valued under a discounted cash flow 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 for the remaining fixed income securities.

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.

Private Equity Funds – These funds consist of investments in private equities that are held by limited partnerships following various strategies, including private equity and corporate finance. These 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. Holdings in these types of private equity funds are negligible, as the funds are well past their expected investment term and have distributed the bulk of proceeds from investment sales.

Derivative Financial Instruments – Futures contracts that are publicly traded in active markets are valued at closing prices as of the last business day of the year. 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 futures contracts are valued at the last sales price quoted on the exchange on which they primarily trade.

While management believes the valuation methods described above 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 10. 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.

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, 2019		
	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Cash and cash equivalents	$ 17	$ —	$ 17
Equity securities:			
Domestic	923	—	923
International	555	1	556
Registered investment companies	96	—	96
Fixed income securities:			
Domestic government bonds	228	39	267
International government bonds	—	9	9
Domestic corporate bonds	—	346	346
International corporate bonds	—	62	62
Registered investment companies	—	2	2
Total investment assets in the fair value hierarchy	$ 1,819	$ 459	2,278
Accounts receivable/payable, net			(38)
Investments measured at NAV:			
Common/collective trusts			417
Private equity funds			5
Total investment assets			$ 2,662
SDG&E's proportionate share of investment assets			$ 739
SoCalGas' proportionate share of investment assets			$ 1,737

	Fair value at December 31, 2018		
	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Cash and cash equivalents	$ 14	$ —	$ 14
Equity securities:			
Domestic	727	—	727
International	437	—	437
Registered investment companies	74	—	74
Fixed income securities:			
Domestic government bonds	197	29	226
International government bonds	—	8	8
Domestic corporate bonds	—	311	311
International corporate bonds	—	53	53
Registered investment companies	—	1	1
Total investment assets in the fair value hierarchy	$ 1,449	$ 402	1,851
Accounts receivable/payable, net			(21)
Investments measured at NAV:			
Common/collective trusts			326
Private equity funds			4
Total investment assets			$ 2,160
SDG&E's proportionate share of investment assets			$ 600
SoCalGas' proportionate share of investment assets			$ 1,385

The fair values by asset category of the PBOP plan assets held in the pension master trust and in the additional trusts for SDG&E's PBOP plan trusts are as follows:

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF OTHER POSTRETIREMENT BENEFIT PLANS

(Dollars in millions)

	Fair value at December 31, 2019		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 21	$ —	$ 21
International	13	—	13
Registered investment companies	68	—	68
Fixed income securities:			
Domestic government bonds	32	1	33
Domestic corporate bonds	—	8	8
International corporate bonds	—	1	1
Registered investment companies	—	8	8
Total investment assets in the fair value hierarchy	134	18	152
Accounts receivable/payable, net			(2)
Investments measured at NAV – Common/collective trusts			47
Total investment assets			197

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF OTHER POSTRETIREMENT BENEFIT PLANS

(Dollars in millions)

	Fair value at December 31, 2018		
	Level 1	Level 2	Total
Cash and cash equivalents	$ 1	$ —	$ 1
Equity securities:			
Domestics	37	—	37
International	22	—	22
Registered investment companies	59	—	59
Fixed income securities:			
Domestic government bonds	10	1	11
Domestic corporate bonds	—	16	16
International corporate bonds	—	3	3
Registered investment companies	—	7	7
Total investment assets in the fair value hierarchy	129	27	156
Accounts receivable/payable, net			(1)
Investments measured at NAV – Common/collective trusts			17
Total investment assets			172

Future Payments

We expect to contribute the following amounts to our pension and PBOP plans in 2020:

EXPECTED CONTRIBUTIONS *(Dollars in millions)*		
Pension plans	$	53
Other postretirement benefit plans		1

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)*		Pension benefits		Other postretirement benefits
2020	$	115	$	10
2021		69		10
2022		64		10
2023		64		10
2024		62		10
2025-2029		283		48

SAVINGS PLANS

SDG&E offers trusteed savings plans to all employees. Employee participation, employee contributions and employer matching contributions are subject to the provisions of the respective plans, and for employee contributions, limits imposed by the respective governmental authorities.

Employer contributions to the savings plans were as follows:

EMPLOYER CONTRIBUTIONS TO SAVINGS PLANS *(Dollars in millions)*		2019		2018		2017
SDG&E	$	15	$	15	$	14

The market value of Sempra Energy common stock held by the savings plans was $1.3 billion and $1.0 billion at December 31, 2019 and 2018, respectively.

NOTE 8. 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:

- nonqualified stock options
- incentive stock options
- restricted stock awards
- restricted stock units
- 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, 2019, Sempra Energy had the following types of equity awards outstanding:

- *Nonqualified Stock Options:* Options to purchase common stock 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 three-year period (for awards granted in 2019) or over a four-year period (for awards granted in 2010 or earlier), 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 or in accordance with the terms of the grant. Options are subject to forfeiture or earlier expiration following termination of employment, subject to certain exceptions.
- *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 (for awards granted prior to 2015) 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 S&P 500 Utilities Index and the S&P 500 Index. We 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% of the number of granted RSUs may be issued.
  - For awards granted during or after 2014, up to an additional 100% of the granted RSUs may be issued if total return to shareholders or EPS growth exceeds target levels.
  - For awards granted in 2015 and 2016 and certain awards granted in 2017 and 2018 that vest based on Sempra Energy's total return to shareholders, a modifier adds 20% 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% for performance in the bottom quartile. However, in no event will more than an additional 100% 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.
- *Service-Based Restricted Stock Units:* RSUs may also be service-based; these generally vest over three-year service periods (for awards granted in 2019), or at the end of three-year (for awards granted during 2015 through 2018) or four-year service periods (for

awards granted prior to 2015).

For RSU awards, vesting may be subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control under the applicable LTIP, 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 RSUs are reinvested to purchase additional common shares that become subject to the same vesting conditions as the RSUs to which the dividends relate.

SHARE-BASED AWARDS AND COMPENSATION EXPENSE

At December 31, 2019, 7,662,352 common 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 nonqualified stock options and RSUs on a straight-line basis over the requisite service period of the award, which is generally three or four years. However, for awards granted to retirement-eligible participants, the expense is recognized over the initial year in which the award was granted as the award requires service through the end of the year in which it was granted. For awards granted to participants who become eligible for retirement during the requisite service period, the expense is recognized over the period between the date of grant and the later of the end of the year in which the award was granted or the date the participant first becomes eligible for retirement. 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. 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.

Sempra Energy subsidiaries record an expense for the plans to the extent that subsidiary employees participate in the plans and/or SDG&E is allocated a portion of the Sempra Energy plans' corporate staff costs. Total share-based compensation expense for all of SDG&E's share-based awards was comprised as follows:

SHARE-BASED COMPENSATION EXPENSE

(Dollars in millions)

	Years ended December 31,

	2019	2018	2017
Share-based compensation expense, before income taxes	$ 10	$ 12	$ 13
Income tax benefit	(3)	(3)	(5)
	$ 7	$ 9	$ 8
Capitalized share-based compensation cost	$ 6	$ 6	$ 5
Excess income tax deficiency	$ 1	$ 3	$ —

SEMPRA ENERGY NONQUALIFIED STOCK OPTIONS

We use a Black-Scholes option-pricing model to estimate the fair value of each nonqualified 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 a blend of the historical and implied volatility of Sempra Energy's common stock price. The average expected term for options is based on the vesting schedule, contractual term of the option, 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 term estimated at the date of the grant. All nonqualified stock options granted prior to 2019 were fully vested and compensation cost on such stock options was fully recognized by December 31, 2014. In January 2019, Sempra Energy's board of directors granted 261,075 nonqualified stock options that are exercisable over a three-year period. The weighted-average per-share fair value for options granted was $13.20 in 2019. To calculate this fair value, we used the Black-Scholes model with the following weighted-average assumptions:

KEY ASSUMPTIONS FOR STOCK OPTIONS GRANTED

	Year ended December 31, 2019
Stock price volatility	18.63%
Expected term	5.34 years
Risk-free rate of return	2.49%
Annual dividend yield	3.35%

The following table shows a summary of nonqualified stock options at December 31, 2019 and activity for the year then ended:

NONQUALIFIED STOCK OPTIONS

	Common shares under	Weighted-average	Weighted-average remaining	Aggregate intrinsic value

	options	exercise price	contractual term (in years)	(in millions)
Outstanding at January 1, 2019	56,940	$ 54.63		
Granted	261,075	$ 106.76		
Exercised	(52,540)	$ 54.52		
Forfeited/canceled	(17,898)	$ 106.76		
Outstanding at December 31, 2019	247,577	$ 105.86	8.85	$ 11
Vested or expected to vest at December 31, 2019	237,236	$ 105.82	8.84	$ 11
Exercisable at December 31, 2019	4,400	$ 55.90	0.01	$ —

The aggregate intrinsic value at December 31, 2019 is the total of the difference between Sempra Energy's closing common stock price and the exercise price for all in-the-money options. The aggregate intrinsic value for nonqualified stock options exercised in the last three years was:

- $4 million in 2019
- $9 million in 2018
- $9 million in 2017

A negligible amount of total compensation cost related to nonvested stock options not yet recognized as of December 31, 2019 is expected to be recognized over a weighted-average period of 2.03 years.

We received cash of $3 million from stock option exercises during 2019.

SEMPRA ENERGY RESTRICTED STOCK UNITS

We use a Monte-Carlo simulation model to estimate the fair value of our RSUs that vest based on Sempra Energy's total return to shareholders. Our determination of fair value is affected by the historical volatility of the common stock price for Sempra Energy and its peer group companies. The valuation also is affected by the risk-free rates of return and a number of other variables. Below are key assumptions for RSUs granted in the last three years:

KEY ASSUMPTIONS FOR RSUs GRANTED

	Years ended December 31,		
	2019	2018	2017
Stock price volatility	17.74%	17.46%	17.24%
Risk-free rate of return	2.46%	2.00%	1.49%

The following table shows a summary of RSUs at December 31, 2019 and activity for the year then ended:

RESTRICTED STOCK UNITS

	Performance-based restricted stock units	Service-based restricted stock units

	Units		Weighted-average grant-date fair value	Units		Weighted-average grant-date fair value
Nonvested at January 1, 2019	1,242,169	$	106.11	402,361	$	105.01
Granted	389,825	$	113.54	260,594	$	112.50
Vested	(142,820)	$	100.28	(209,395)	$	102.68
Forfeited	(402,193)	$	103.34	(37,773)	$	110.25
Nonvested at December 31, 2019(1)	1,086,981	$	109.85	415,787	$	119.96
Expected to vest at December 31, 2019	1,066,375	$	109.89	408,782	$	109.65

(1) *Each RSU represents the right to receive one share of our common stock if applicable performance conditions are satisfied. For all performance-based RSUs, up to an additional 100% of the shares represented by the RSUs may be issued if Sempra Energy exceeds target performance conditions.*

In 2019, 2018 and 2017, the total fair value of RSU shares vested during the year was $36 million, $32 million and $45 million, respectively.

The $32 million of total compensation cost related to nonvested RSUs not yet recognized as of December 31, 2019 is expected to be recognized over a weighted-average period of 2.07 years. The weighted-average per-share fair values for performance-based RSUs granted were $105.03 and $110.54 in 2018 and 2017, respectively. The weighted-average per-share fair values for service-based RSUs granted were $107.60 and $101.88 in 2018 and 2017, respectively

NOTE 9. DERIVATIVE FINANCIAL INSTRUMENTS

We use derivative instruments primarily to manage exposures arising in the normal course of business. Our principal exposures are commodity market risk and benchmark interest rate risk. 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 tables 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 have derivatives that are (1) cash flow hedges, (2) fair value hedges, or (3) undesignated. Depending on the applicability of hedge accounting and other operations subject to regulatory accounting, the requirement to pass impacts through to customers, the impact of derivative instruments may be offset in OCI (cash flow hedges), on the balance sheet (regulatory offsets), or recognized in earnings (fair value hedges). We classify cash flows from the settlements of other derivative instruments as operating activities on the Statement of Cash Flows.

HEDGE 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 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.

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:

- 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.
- We are allocated and may purchase 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 and GHG allowances.

The following table summarizes net energy derivative volumes.

NET ENERGY DERIVATIVE VOLUMES
(Quantities in millions)

		December 31,	
Commodity	Unit of measure	2019	2018
Natural gas	MMBtu	37	33
Electricity	MWh	2	2
Congestion revenue rights	MWh	48	52

In addition to the amounts noted above, we 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 Balance Sheet reflects the offsetting of net derivative positions and cash collateral with the same counterparty when a legal right of offset exists. The following tables provide the fair values of derivative instruments on the Balance Sheet, including the amount of cash collateral receivables that were not offset, as the cash collateral was in excess of liability positions.

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET
(Dollars in millions)

December 31, 2019

	Other current assets(1)	Other long-term assets	Other current liabilities	Deferred credits and other
Derivatives not designated as hedging instruments:				
Commodity contracts subject to rate recovery	$ 30	$ 76	$ (41)	$ (47)
Associated offsetting commodity contracts	(4)	(3)	4	3
Associated offsetting cash collateral	—	—	14	—
Net amounts presented on the balance sheet	26	73	(23)	(44)
Additional cash collateral for commodity contracts subject to rate recovery	16	—	—	—
Total(2)	$ 42	$ 73	$ (23)	$ (44)

(1) *Included in Current Assets: Fixed-Price Contracts and Other Derivatives.*

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

DERIVATIVE INSTRUMENTS ON THEBALANCE SHEET

(Dollars in millions)

	December 31, 2018			
	Other current assets(1)	Other long-term assets	Other current liabilities	Deferred credits and other
Derivatives not designated as hedging instruments:				
Commodity contracts subject to rate recovery	$ 60	$ 233	$ (37)	$ (72)
Associated offsetting commodity contracts	(6)	(2)	6	2
Associated offsetting cash collateral	—	—	—	2
Net amounts presented on the balance sheet	54	231	(31)	(68)
Additional cash collateral for commodity contracts subject to rate recovery	28	—	—	—
Total(2)	$ 82	$ 231	$ (31)	$ (68)

(1) *Included in Current Assets: Fixed-Price Contracts and Other Derivatives.*

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

The following table summarizes the effects of derivative instruments not designated as hedging instruments on the Statement of Operations.

UNDESIGNATED DERIVATIVE IMPACTS

(Dollars in millions)

Pretax gain (loss) on derivatives recognized in earnings

Years ended December 31,

	Location	2019	2018	2017
Commodity contracts subject to rate recovery	Cost of Electric Fuel and Purchased Power	$ (140)	$ 279	$ 54

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.

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 10. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASURES

The table below, by level within the fair value hierarchy, set forth our financial assets and liabilities that were accounted for at fair value on a recurring basis at December 31, 2019 and 2018. 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-valued assets and liabilities, and their placement within the fair value hierarchy.

The fair value of commodity derivative assets and liabilities is presented in accordance with our netting policy, as we discuss in Note 9 under “Financial Statement Presentation.”

The determination 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 financial assets and liabilities that were accounted for at fair value on a recurring basis in the tables below include the following:

- Nuclear decommissioning trusts reflect the assets of SDG&E’s NDT, 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. 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 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 or income 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, 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, 2019 and 2018.

RECURRING FAIR VALUE MEASURES

(Dollars in millions)

	Fair value at December 31, 2019			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts:				
Equity securities	$ 503	$ 6	$ —	$ 509

	Level 1	Level 2	Level 3	Total
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	46	11	—	57
Municipal bonds	—	282	—	282
Other securities	—	226	—	226
Total debt securities	46	519	—	565
Total nuclear decommissioning trusts(1)	549	525	—	1,074
Commodity contracts subject to rate recovery	1	3	95	99
Effect of netting and allocation of collateral(2)	10	—	6	16
Total	$ 560	$ 528	$ 101	$ 1,189
Liabilities:				
Commodity contracts subject to rate recovery	14	—	67	81
Effect of netting and allocation of collateral(2)	(14)	—	—	(14)
Total	$ —	$ —	$ 67	$ 67

	Fair value at December 31, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts:				
Equity securities	$ 407	$ 4	$ —	$ 411
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	43	10	—	53
Municipal bonds	—	269	—	269
Other securities	—	234	—	234
Total debt securities	43	513	—	556
Total nuclear decommissioning trusts(1)	450	517	—	967
Commodity contracts subject to rate recovery	1	6	278	285
Effect of netting and allocation of collateral(2)	23	—	5	28
Total	$ 474	$ 523	$ 283	$ 1,280
Liabilities:				
Commodity contracts subject to rate recovery	2	—	99	101
Effect of netting and allocation of collateral(2)	(2)	—	—	(2)
Total	$ —	$ —	$ 99	$ 99

(1) *Excludes cash balances and cash equivalents.*

(2) *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.*

Level 3 Information

The table below 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 for SDG&E.

LEVEL 3 RECONCILIATIONS(1)

(Dollars in millions)

Years ended December 31,

	2019	2018	2017
Balance at January 1	$ 179	$ (28)	$ (74)
Realized and unrealized gains (losses)	(184)	209	34
Allocated transmission instruments	6	10	6
Settlements	27	(12)	6
Balance at December 31	$ 28	$ 179	$ (28)
Change in unrealized gains (losses) relating to instruments still held at December 31	$ (139)	$ 183	$ 30

(1) *Excludes the effect of the contractual ability to settle contracts under master netting agreements.*

Inputs used to determine the fair value of CRRs and fixed-price electricity positions are reviewed and compared with market conditions to determine reasonableness. SDG&E expects 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 are the basis for valuing CRRs settling in the following year. For the CRRs settling from January 1 to December 31, the auction price inputs, at a given location, were in the following ranges for the years indicated below:

CONGESTION REVENUE RIGHTS AUCTION PRICE INPUTS

Settlement year	Price per MWh			Median price per MWh
2020	$ (3.77)	to	$ 6.03	$ (1.58)
2019	(8.57)	to	35.21	(2.94)
2018	(7.25)	to	11.99	0.09

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. 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 9.

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. The range and weighted-average price of these inputs were as follows:

LONG-TERM, FIXED-PRICE ELECTRICITY POSITIONS PRICE INPUTS

Settlement year	Price per MWh	Weighted-average price per MWh

2019	$	21.00	to	$ 61.15	$	37.92
2018		22.20	to	76.85		42.69

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 9.

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. Because unrealized gains and losses are recorded as regulatory assets and liabilities, they do not affect earnings.

Fair Value of Financial Instruments

The fair values of certain of our financial instruments (cash, accounts and notes receivable, short-term amounts 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.

FAIR VALUE OF FINANCIAL INSTRUMENTS
(Dollars in millions)

	December 31, 2019				
	Carrying	Fair value			
	amount	Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 5,140	$ —	$ 5,662	$ —	$ 5,662
	December 31, 2018				
	Carrying	Fair value			
	amount	Level 1	Level 2	Level 3	Total
SDG&E:					
Total long-term debt(2)	$ 4,776	$ —	$ 4,897	$ —	$ 4,897

(1) *Before reductions of unamortized discount and debt issuance costs of $48 million and excluding finance lease obligations of $1,270 million.*

(2) *Before reductions of unamortized discount and debt issuance costs of $47 million and excluding capital lease obligations of $1,585 million.*

We provide the fair values for the securities held in the NDT related to SONGS in Note 12.

NOTE 11. PREFERRED STOCK

SDG&E is authorized to issue up to 45 million shares of preferred stock. At December 31, 2019 and 2018, SDG&E had no preferred stock outstanding. The rights, preferences, privileges and restrictions for any new series of preferred stock would be established by each company's board of directors at the time of issuance.

NOTE 12. SAN ONOFRE NUCLEAR GENERATING STATION

SDG&E has a 20% ownership interest in SONGS, a nuclear generating facility near San Clemente, California, which permanently ceased operations in June 2013 after an extended outage as a result of issues with the steam generators used in the facility. 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 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 costs. SDG&E's share of operating expenses is included in SDG&E's Statement of Operations.

SONGS STEAM GENERATOR REPLACEMENT PROJECT

The replacement steam generators, which caused a water leak due to unexpected tube wear, were designed and provided by MHI. In 2013, Edison instituted arbitration proceedings against MHI seeking recovery of damages resulting from the issues with the steam generators used in SONGS Units 2 and 3. The other SONGS co-owners, SDG&E and the City of Riverside, participated as claimants and respondents.

In March 2017, the International Chamber of Commerce International Court of Arbitration Tribunal (the Tribunal) overseeing the arbitration found MHI liable for breach of contract, subject to a contractual limitation of liability, and rejected claimants' other claims. The Tribunal awarded $118 million in damages to the SONGS co-owners, but determined that MHI was the prevailing party and awarded it 95% of its arbitration costs. The damage award is offset by these costs, resulting in a net award of approximately $60 million in favor of the SONGS co-owners. SDG&E's specific allocation of the damage award was $24 million reduced by costs awarded to MHI of approximately $12 million, resulting in a net damage award of $12 million, which was paid by MHI to SDG&E in March 2017. In accordance with the Amended Settlement Agreement discussed below, SDG&E recorded the proceeds from the MHI arbitration by reducing O&M for previously incurred legal costs of $11 million, and shared the remaining $1 million equally between ratepayers and shareholders.

SETTLEMENT AGREEMENT TO RESOLVE THE CPUC'S ORDER INSTITUTING INVESTIGATION INTO THE SONGS OUTAGE

In 2012, in response to the SONGS 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 the outage.

In 2014, the CPUC issued a final decision approving an Amended Settlement Agreement that provided for various disallowances, refunds and rate recoveries, including authorizing SDG&E to recover in rates its remaining investment in SONGS, excluding its investment in the Steam Generator Replacement Project.

In 2016, the CPUC issued two procedural rulings: the first, to reopen the record of the OII to address the issue of whether the Amended Settlement Agreement is reasonable and in the public interest, and the second, 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.

In July 2018, the CPUC approved a Revised Settlement Agreement among SDG&E, Edison, Cal PA, TURN and other intervenors that resolved all issues under consideration in the SONGS OII and made one modification to the Amended Settlement Agreement to remove the requirement to fund a GHG emissions reduction research program. In August 2018, parties to the Revised Settlement Agreement submitted a notice that they accepted the settlement agreement, as modified.

In connection with the Revised Settlement Agreement, and in exchange for the release of certain SONGS-related claims, SDG&E and Edison entered into the Utility Shareholder Agreement, described below.

Disallowances, Refunds and Recoveries

Under the Revised Settlement Agreement, SDG&E and Edison ceased rate recovery of SONGS costs as authorized under the Amended Settlement Agreement as of December 19, 2017, when the present value of their combined remaining SONGS regulatory assets equaled $775 million, of which $152 million represents SDG&E’s share. Under the Utility Shareholder Agreement, Edison is obligated to pay SDG&E the full amount of SDG&E’s revenue requirement not recovered from ratepayers, as described below. In October 2018, SDG&E began refunding to customers SONGS-related amounts recovered in rates after December 19, 2017.

Utility Shareholder Agreement

In January 2018, SDG&E and Edison entered into the Utility Shareholder Agreement under which Edison has an obligation to compensate SDG&E for the revenue requirement amounts that SDG&E will no longer recover because of the Revised Settlement Agreement. In exchange for Edison’s reimbursement, the parties mutually released each other from all claims that each party had or could have asserted related to the steam generator replacement failure and its aftermath. The Utility Shareholder Agreement became effective upon CPUC approval of the Revised Settlement Agreement. Edison’s payment obligation commenced in October 2018, and amounts are due to SDG&E quarterly thereafter until April 2022. At December 31, 2019, SDG&E has a receivable from Edison, including accrued interest, totaling $86 million, with $38 million classified as current and $48 million classified as noncurrent. This receivable reflects amounts Edison is obligated to pay to SDG&E in lieu of amounts SDG&E would have collected from ratepayers associated with the SONGS regulatory asset.

NUCLEAR DECOMMISSIONING AND FUNDING

As a result of Edison’s decision to permanently retire SONGS Units 2 and 3, Edison began the decommissioning phase of the plant. We expect the majority of the dismantlement work to take 10 years after receipt of the required permits. The coastal development permit was issued in October 2019. The Samuel Lawrence Foundation filed a writ petition under the California Coastal Act in LA Superior Court in December 2019. The petition seeks to invalidate the permit and to obtain injunctive relief to stop decommissioning work. We expect major decommissioning work to begin in 2020, unless the court issues an injunction. Decommissioning of Unit 1, removed from service in 1992, is largely complete. The remaining work for Unit 1 will be completed once Units 2 and 3 are dismantled and the spent fuel is removed from the site. The spent fuel is currently being stored on-site, until the DOE identifies a spent fuel storage facility and puts in place a program for the fuel’s disposal, as we discuss below. SDG&E is responsible for approximately 20% of the total contract price.

In accordance with state and federal requirements and regulations, SDG&E has assets held in the NDT to fund its share of decommissioning costs for SONGS Units 1, 2 and 3. 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 NDT are invested in accordance with CPUC regulations. SDG&E classifies debt and equity securities held in the NDT as available-for-sale. The NDT assets are presented on the Balance Sheet at fair value with the offsetting credits recorded in noncurrent Regulatory Liabilities.

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. SDG&E has received authorization from the CPUC to access NDT funds of up to $455 million for 2013 through 2019 SONGS decommissioning costs. SDG&E has filed for authorization with the CPUC to withdraw up to $109 million from the NDT for forecasted 2020 SONGS Units 2 and 3 costs as decommissioning costs are incurred.

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 trust 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. SDG&E is awaiting the adoption of, or additional refinement to, the proposed regulations before determining whether the proposed regulations will allow SDG&E to timely access the NDT funds for reimbursement or payment of the spent fuel management costs incurred in 2017 and subsequent years. Further clarification of the proposed regulations could enable SDG&E to access the NDT to recover spent fuel management costs before Edison reaches final settlement with the DOE regarding the DOE's reimbursement of these costs. Historically, the DOE's reimbursements of spent fuel storage costs have not resulted in timely or complete recovery of these costs. We discuss the DOE's responsibility for spent nuclear fuel below. The IRS held public hearings on the proposed regulations in October 2017. It is unclear when clarification of the proposed regulations might be provided or when the proposed regulations will be finalized.

Nuclear Decommissioning 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 the Balance Sheet at fair value with the offsetting credits recorded in noncurrent Regulatory Liabilities.

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 10.

NUCLEAR DECOMMISSIONING TRUSTS
(Dollars in millions)

	Cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value
At December 31, 2019:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies(1)	$ 57	$ —	$ —	$ 57
Municipal bonds(2)	270	12	—	282

Other securities(3)	218	9	(1)	226
Total debt securities	545	21	(1)	565
Equity securities	176	339	(6)	509
Cash and cash equivalents	8	—	—	8
Total	$ 729	$ 360	$ (7)	$ 1,082
At December 31, 2018:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	$ 52	$ 1	$ —	$ 53
Municipal bonds	266	4	(1)	269
Other securities	238	1	(5)	234
Total debt securities	556	6	(6)	556
Equity securities	168	253	(10)	411
Cash and cash equivalents	7	—	—	7
Total	$ 731	$ 259	$ (16)	$ 974

(1) *Maturity dates are 2021-2050.*

(2) *Maturity dates are 2020-2056.*

(3) *Maturity dates are 2020-2072.*

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 IN THE NDT

(Dollars in millions)

	Years ended December 31,		
	2019	2018	2017
Proceeds from sales	$ 914	$ 890	$ 1,314
Gross realized gains	24	42	157
Gross realized losses	(5)	(10)	(14)

Net unrealized gains and losses, as well as realized gains and losses that are reinvested in the NDT, are included in noncurrent Regulatory Liabilities on SDG&E's Balance Sheet. We determine the cost of securities in the trusts on the basis of specific identification.

ASSET RETIREMENT OBLIGATION AND SPENT NUCLEAR FUEL

The present value of SDG&E's ARO related to decommissioning costs for the SONGS units was $611 million at December 31, 2019. 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 ARO for all three units is based on a cost study prepared in 2017 that is pending CPUC approval. The ARO for Units 2 and 3 reflects the acceleration of the start of decommissioning of these units as a result of the early closure of the plant. SDG&E's share of total decommissioning costs in 2019 dollars is approximately $834 million. We expect SDG&E's undiscounted SONGS decommissioning payments to be $89 million in 2020, $82 million in 2021, $83 million in 2022, $63 million in 2023, $46 million in 2024, and $739 million thereafter.

U.S. DEPARTMENT OF ENERGY NUCLEAR FUEL DISPOSAL

Spent nuclear fuel from SONGS is currently stored on-site in an ISFSI licensed by the NRC or temporarily in spent fuel pools. In October 2015, the CCC approved Edison's application for the proposed expansion of the ISFSI at SONGS. The ISFSI expansion began construction in 2016 and the transfer of the spent nuclear fuel from Units 2 and 3 to the ISFSI began in 2018. Edison suspended this transfer in August 2018 due to an incident that was subsequently resolved to the NRC's satisfaction according to the NRC's supplemental inspection report released in July 2019. Edison resumed spent fuel transfer operations in July 2019. The ISFSI 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. Until then, SONGS owners are responsible for interim storage of spent nuclear fuel at SONGS.

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. In November 2019, Edison filed a claim for spent fuel management costs in the U.S. Court of Federal Claims for the time period from January 2017 through July 2018. It is unclear when Edison will pursue litigation claims for spent fuel management costs incurred on or after August 1, 2018. 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.

NUCLEAR INSURANCE

SDG&E and the other owners of SONGS have insurance to cover claims from nuclear liability incidents arising at SONGS. Currently, this insurance provides $450 million in coverage limits, the maximum amount available, including coverage for acts of terrorism. In addition, the Price-Anderson Act provides an additional $110 million of coverage. If a nuclear liability loss occurs at SONGS and exceeds the $450 million insurance limit, this additional coverage would be available to provide a total of $560 million in coverage limits per incident.

The SONGS owners, including SDG&E, also maintain nuclear property damage insurance at $1.5 billion, with a $500 million property damage sublimit on the ISFSI, which exceeds the minimum federal requirements of $1.06 billion. This insurance coverage is provided through 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.

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) of $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.

NOTE 13. COMMITMENTS AND CONTINGENCIES

LEGAL PROCEEDINGS

We accrue 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 reasonably estimate 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, 2019, SDG&E did not have loss contingency accruals for legal matters, including associated legal fees, that are probable. We discuss our policy regarding accrual of legal fees in Note 1.

SDG&E

2007 Wildfire Litigation and Net Cost Recovery Status

SDG&E has resolved all litigation associated with three wildfires that occurred in October 2007.

As a result of a CPUC decision denying SDG&E’s request to recover wildfire costs, SDG&E wrote off the wildfire regulatory asset, resulting in a charge of $351 million ($208 million after tax) in the third quarter of 2017. SDG&E applied to the CPUC for rehearing of its decision but, in July 2018, the CPUC denied SDG&E’s rehearing request. In November 2018, the California Court of Appeal denied SDG&E’s petition to reverse the CPUC’s decision. In January 2019, the California Supreme Court denied SDG&E’s petition to reverse the decisions of the CPUC and the California Court of Appeal. In October 2019, the U.S. Supreme Court declined to review the decision, effectively ending SDG&E’s efforts to recover the wildfire regulatory asset.

LEASES

A lease exists when a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. We determine if an arrangement is or contains a lease at inception of the contract.

Some of our lease agreements contain nonlease components, which represent activities that transfer a separate good or service to the lessee. As the lessee for both operating and finance leases, we have elected to combine lease and nonlease components as a single lease component for real estate, fleet vehicles, power generating facilities, and pipelines, whereby fixed or in-substance fixed payments allocable to the nonlease component are accounted for as part of the related lease liability and ROU asset. As the lessor, we have elected to combine lease and nonlease components as a single lease component for real estate and power generating facilities if the timing and pattern of transfer of the lease and nonlease components are the same and the lease component would be classified as an operating lease if accounted for separately.

Lessee Accounting

We have operating and finance leases for real and personal property (including office space, land, fleet vehicles, machinery and equipment, warehouses and other operational facilities) and PPAs with renewable energy and peaker plant facilities.

Some of our leases include options to extend the lease terms for up to 25 years, while others include options to terminate the lease within one year. Our lease liabilities and ROU assets are based on lease terms that may include such options to extend or terminate the lease when it is reasonably certain that we will exercise that option.

Certain of our contracts are short-term leases, which have a lease term of 12 months or less at lease commencement. We do not recognize a lease liability or ROU asset arising from short-term leases for all existing classes of underlying assets. In such cases, we recognize short-term lease costs on a straight-line basis over the lease term. Our short-term lease costs for the period reasonably reflect our short-term lease commitments.

Certain of our leases contain escalation clauses requiring annual increases in rent ranging from 2% to 4% or based on the Consumer Price Index. The rentals payable under these leases may increase by a fixed amount each year or by a percentage of a base year. Variable lease payments that are based on an index or rate are included in the initial measurement of our lease liability and ROU asset based on the index or rate at lease commencement and are not remeasured because of changes to the index or rate. Rather, changes to the index or rate are treated as variable lease payments and recognized in the period in which the obligation for those payments is incurred.

Similarly, PPAs for the purchase of renewable energy at SDG&E require lease payments based on a stated rate per MWh produced by the facilities, and we are required to purchase substantially all the output from the facilities. SDG&E is required to pay additional amounts for capacity charges and actual purchases of energy that exceed the minimum energy commitments. Under these contracts, we do not recognize a lease liability or ROU asset for leases for which there are no fixed lease payments. Rather, these variable lease payments are recognized separately as variable lease costs. SDG&E estimates these variable lease payments to be $326 million in 2020, $328 million in 2021, $328 million in 2022, $327 million in 2023, $328 million in 2024 and $3,707 million thereafter.

As of the lease commencement date, we recognize a lease liability for our obligation to make future lease payments, which we initially measure at present value using our incremental borrowing rate at the date of lease commencement, unless the rate implicit in the lease is readily determinable. We determine our incremental borrowing rate based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We also record a ROU asset for our right to use the underlying asset, which is initially equal to the lease liability and adjusted for lease payments made at or before lease commencement, lease incentives, and any initial direct costs. Like other long-lived assets, we test ROU assets for recoverability whenever events or changes in circumstances have occurred that may affect the recoverability or the estimated useful lives of the ROU assets.

For our operating leases, we recognize a single lease cost on a basis that is consistent with the recovery of such costs in accordance with U.S. GAAP governing rate-regulated operations.

For our finance leases, the interest expense on the lease liability and amortization of the ROU asset are accounted for separately. We recognize amortization of the ROU asset on a basis that is consistent with the recovery of such costs in accordance with U.S. GAAP governing rate-regulated operations.

Our leases do not contain any material residual value guarantees, restrictions or covenants.

Classification of ROU assets and lease liabilities and the weighted-average remaining lease term and discount rate associated with operating and finance leases are summarized in the table below.

LESSEE INFORMATION ON THE BALANCE SHEET *(Dollars in millions)*	
	December 31, 2019
Right-of-use assets:	
Operating leases:	
Right-of-use assets (included in Capital Lease Accounts)	$ 130
Finance leases:	

Property, plant and equipment		1,326
Accumulated depreciation		(57)
Property, plant and equipment, net		1,269
Total right-of-use assets	$	1,399
Lease liabilities:		
Operating leases:		
Other current liabilities	$	27
Deferred credits and other		102
		129
Finance leases:		
Current portion of long-term debt and finance leases		20
Long-term debt and finance leases		1,250
		1,270
Total lease liabilities	$	1,399
Weighted-average remaining lease term (in years):		
Operating leases		6
Finance leases		20
Weighted-average discount rate:		
Operating leases		3.55%
Finance leases		14.83%

The table below presents the maturity analysis of our lease liabilities and reconciliation to the present value of lease liabilities:

LESSEE MATURITY ANALYSIS OF LIABILITIES
(Dollars in millions)

	December 31, 2019			
	Operating leases		Finance leases	
2020	$	30	$	192
2021		32		190
2022		22		190
2023		17		190

2024	15	185
Thereafter	28	2,624
Total undiscounted lease payments	144	3,571
Less: imputed interest	(15)	(2,301)
Total lease liabilities	129	1,270
Less: current lease liabilities	(27)	(20)
Long-term lease liabilities	$ 102	$ 1,250

Leases that Have Not Yet Commenced

SDG&E has lease agreements for future acquisitions of fleet vehicles with an aggregate maximum lease limit of $174 million. SDG&E has utilized $54 million of these maximum limits as of December 31, 2019.

Lease Disclosures Under Previous U.S. GAAP

Rent expense for operating leases was as follows:

RENT EXPENSE – OPERATING LEASES
(Dollars in millions)

	Years ended December 31,	
	2018	2017
SDG&E	$ 27	$ 28

The annual amortization charge for PPAs accounted for as capital leases at SDG&E was $11 million and $8 million in 2018 and 2017, respectively. The annual depreciation charge for fleet vehicles and other assets in 2018 and 2017 was $2 million and $1 million, respectively, at SDG&E.

The table below presents the future minimum lease payments under previous U.S. GAAP:

FUTURE MINIMUM LEASE PAYMENTS
(Dollars in millions)

	December 31, 2018	
	Operating leases	Capital leases
2019	$ 23	$ 540
2020	22	210
2021	22	211
2022	21	211

2023	17	211
Thereafter	48	3,196
Total undiscounted lease payments	$ 153	4,579
Less: estimated executory costs		(480)
Less: imputed interest		(2,500)
Total future minimum lease payments		$ 1,599

.

CONTRACTUAL COMMITMENTS

Natural Gas Contracts

SoCalGas has responsibility for procuring natural gas for both SDG&E's and SoCalGas' core customers in a combined portfolio. SoCalGas buys natural gas under short-term and long-term contracts for this portfolio from various producing regions in the southwestern U.S., U.S. Rockies and Canada, primarily based on published monthly bid-week indices.

SoCalGas transports natural gas primarily under long-term firm interstate pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. SoCalGas has commitments with interstate pipeline companies for firm pipeline capacity under contracts that expire at various dates through 2031.

Purchased-Power Contracts

For 2020, SDG&E expects to meet its customer power requirements from the following resource types:

- Long-term contracts: 27% (of which 26% is provided by renewable energy contracts expiring on various dates through 2041)
- Other SDG&E-owned generation and tolling contracts: 59%
- Spot market purchases: 14%

Payments on our purchased-power contracts could exceed the minimum commitments based on energy needs. At December 31, 2019, the future minimum payments under long-term purchased-power contracts for SDG&E are as follows:

FUTURE MINIMUM PAYMENTS – PURCHASED-POWER CONTRACTS *(Dollars in millions)*	
2020	$ 233
2021	229
2022	233
2023	194
2024	166
Thereafter	904

Total minimum payments[1]	$	1,959

(1) *Excludes purchase agreements accounted for as finance 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 for SDG&E were $744 million in 2019, $712 million in 2018 and $781 million in 2017.

Construction and Development Projects

At December 31, 2019, SDG&E has commitments to make future payments of $57 million for construction projects that include:

- $49 million for infrastructure improvements for electric and natural gas transmission and distribution systems; and
- $8 million related to spent fuel management at SONGS.

SDG&E expects future payments under these contractual commitments to be $20 million in 2020, $19 million in 2021, $14 million in 2022, $1 million in 2023, $1 million in 2024 and $2 million thereafter.

OTHER COMMITMENTS

We discuss nuclear insurance and nuclear fuel disposal related to SONGS in Note 12.

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, for which a liability has been recorded, are expected to be $4 million per year in 2020 through 2024 and $282 million thereafter, subject to escalation of 2% per year, for a remaining 50-year period. At December 31, 2019, the present value of these future payments of $121 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.

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 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,		
	2019	2018	2017
SDG&E	$ 39	$ 38	$ 46

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 the manufactured-gas sites, (2) cleanup of third-party waste-disposal sites used by us at 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, 2019 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

	# Sites complete(1)	# Sites in process
SDG&E:		
Manufactured-gas sites	3	—
Third-party waste-disposal sites	2	1

(1) *There may be ongoing compliance obligations for completed sites, such as regular inspections, adherence to land use covenants and water quality monitoring.*

We record the present value of environmental liabilities 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, 2019.

ACCRUED LIABILITIES FOR ENVIRONMENTAL MATTERS
(Dollars in millions)

	Manufactured-gas sites	Waste disposal sites (PRP)(1)	Other hazardous waste sites	Total(2)

SDG&E[3]	$ —	$ 2	$ 3	$ 5

(1) Sites for which we have been identified as a PRP.

(2) Includes $1 million classified as current liabilities, and $4 million classified as noncurrent liabilities on SDG&E's Balance Sheet.

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

In connection with the issuance of operating permits, SDG&E and the other owners of SONGS previously reached an agreement with the 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 12, does not reduce SDG&E's mitigation obligation. SDG&E's share of the estimated mitigation costs is $85 million, of which $46 million has been incurred through December 31, 2019 and $39 million is accrued for remaining costs through 2053, which is recoverable in rates and included in noncurrent Regulatory Assets on SDG&E's Balance Sheet. 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 2018, the CPUC approved a joint motion filed by SDG&E, Edison, TURN and Cal PA requesting approval of a settlement agreement that amends the rate recovery application and allows costs to be recorded to a memorandum account until rate recovery is approved. In August 2019, Edison and SDG&E submitted an updated cost forecast to the CPUC for rate recovery approval when the project's coastal development permit was approved. The CPUC approved the updated cost forecast in December 2019, with rates going into effect on January 1, 2020. SDG&E's share of the reef expansion costs currently forecasted through September 2020 is approximately $4 million, of which $3 million has been incurred through December 31, 2019 and $1 million is payable for remaining costs through September 2020.

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

GLOSSARY	
2016 GRC FD	final decision in the California Utilities' 2016 General Rate Case
2019 GRC FD	final decision in the California Utilities' 2019 General Rate Case
AB	California Assembly Bill
AFUDC	allowance for funds used during construction
AOCI	accumulated other comprehensive income (loss)
ARO	asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update

bps	basis points
Cal PA	California Public Advocates Office
California Utilities	San Diego Gas & Electric Company and Southern California Gas Company, collectively
Cameron LNG JV	Cameron LNG Holdings, LLC
CARB	California Air Resources Board
CCM	cost of capital adjustment mechanism
CPUC	California Public Utilities Commission
CRR	congestion revenue right
DOE	U.S. Department of Energy
DWR	California Department of Water Resources
Edison	Southern California Edison Company, a subsidiary of Edison International
Enova	Enova Corporation
EPS	earnings per common share
ETR	effective income tax rate
FERC	Federal Energy Regulatory Commission
GCIM	Gas Cost Incentive Mechanism
GHG	greenhouse gas
GRC	General Rate Case
IOU	investor-owned utility
IRC	U.S. Internal Revenue Code of 1986 (as amended)
IRS	Internal Revenue Service
ISFSI	independent spent fuel storage installation
ISO	Independent System Operator
JV	joint venture
LA Superior Court	Los Angeles County Superior Court
LIFO	last in first out
LNG	liquefied natural gas
LTIP	long-term incentive plan
MHI	Mitsubishi Heavy Industries, Ltd., Mitsubishi Nuclear Energy Systems, Inc., and Mitsubishi Heavy Industries America, Inc., collectively
MMBtu	million British thermal units (of natural gas)
Moody’s	Moody’s Investors Service, Inc.
MW	megawatt
MWh	megawatt hour

GLOSSARY (CONTINUED)

NAV	net asset value
NDT	nuclear decommissioning trusts
NEIL	Nuclear Electric Insurance Limited
NOL	net operating loss
NRC	Nuclear Regulatory Commission
OCI	other comprehensive income (loss)
OII	Order Instituting Investigation
O&M	operation and maintenance expense
OMEC	Otay Mesa Energy Center

OMEC LLC	Otay Mesa Energy Center LLC
PBOP	postretirement benefits other than pension
PG&E	Pacific Gas and Electric Company
PPA	power purchase agreement
PP&E	property, plant and equipment
PRP	Potentially Responsible Party
RBS	The Royal Bank of Scotland plc
REC	renewable energy certificate
ROE	return on equity
ROU	right-of-use
RPS	Renewables Portfolio Standard
RSU	restricted stock unit
SDG&E	San Diego Gas & Electric Company
SEC	U.S. Securities and Exchange Commission
SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
SONGS OII	CPUC's Order Instituting Investigation into the SONGS Outage
S&P	Standard & Poor's Global Ratings
TCJA	Tax Cuts and Jobs Act of 2017
TO4	Electric Transmission Owner Formula Rate, effective through December 31, 2018
TO5	Electric Transmission Owner Formula Rate, new application
TURN	The Utility Reform Network
U.S. GAAP	accounting principles generally accepted in the United States of America
Wildfire Fund	the fund established pursuant to AB 1054
Wildfire Legislation	AB 1054 and AB 111

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	04/17/2020	End of 2019/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		(8,217,268)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(1,360,811)		
4	Total (lines 2 and 3)		(1,360,811)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(9,578,079)		
6	Balance of Account 219 at Beginning of Current Year		(9,578,079)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(6,295,969)		
9	Total (lines 7 and 8)		(6,295,969)		
10	Balance of Account 219 at End of Current Quarter/Year		(15,874,048)		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(8,217,268)		
2					
3			(1,360,811)		
4			(1,360,811)	666,868,924	665,508,113
5			(9,578,079)		
6			(9,578,079)		
7					
8			(6,295,969)		
9			(6,295,969)	769,183,643	762,887,674
10			(15,874,048)		

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	04/17/2020	End of 2019/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)	19,571,112,942	15,576,853,691
4	Property Under Capital Leases	1,488,133,886	1,307,422,018
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	21,059,246,828	16,884,275,709
9	Leased to Others	112,194,000	112,194,000
10	Held for Future Use		
11	Construction Work in Progress	1,500,632,606	1,129,880,014
12	Acquisition Adjustments	3,750,722	3,750,722
13	Total Utility Plant (8 thru 12)	22,675,824,156	18,130,100,445
14	Accum Prov for Depr, Amort, & Depl	7,079,972,729	5,461,462,474
15	Net Utility Plant (13 less 14)	15,595,851,427	12,668,637,971
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,322,141,680	5,167,252,017
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	732,796,502	269,175,910
22	Total In Service (18 thru 21)	7,054,938,182	5,436,427,927
23	Leased to Others		
24	Depreciation	23,034,163	23,034,163
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	23,034,163	23,034,163
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	2,000,384	2,000,384
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,079,972,729	5,461,462,474

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
2,535,449,608				1,458,809,643	3
				180,711,868	4
					5
					6
					7
2,535,449,608				1,639,521,511	8
					9
					10
112,945,810				257,806,782	11
					12
2,648,395,418				1,897,328,293	13
859,496,143				759,014,112	14
1,788,899,275				1,138,314,181	15
					16
					17
850,476,926				304,412,737	18
					19
					20
9,019,217				454,601,375	21
859,496,143				759,014,112	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
859,496,143				759,014,112	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	04/17/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 33 Column: b

Reclassification as of 12/2019 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	143,542,725
Steam Production Plant	256,187,298
Other Production Plant	262,829,983
Transmission Plant	1,315,464,798
Distribution Plant	3,211,614,730
General Plant	184,120,525
Ratemaking Electric	5,373,760,059
Nuclear Decommissioning	1,081,497,593
ASC 410 (FAS 143 and FIN 47) - Electric	(1,087,333,703)
Capital Leases A/D	52,648,615
Leased to Others- Citizens A/D (Sunrise)	22,771,925
Leased to Others- Citizens A/D (SX-PQ)	262,238
Cuyamaca Permanent Adjustment	17,855,747
Total Electric	5,461,462,474
Ratemaking Gas	1,070,878,558
FIN 47 - Gas	(211,382,415)
Total Gas	859,496,143
Ratemaking Common	719,060,107
FIN 47 - Common	3,377,489
Capital Lease A/D	36,576,516
Total Common	759,014,112
Total Accumulated Provision EOQ 12/2019	7,079,972,729
Total 13-Month Average Accum. Provision as of 12/31/2019 -Steam Production	243,775,470
Total 13-Month Average Accum. Provision as of 12/31/2019 -Other Production	250,560,861
Total 13-Month Average Accum. Provision as of 12/31/2019 -Transmission Plant	1,250,473,695

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)		

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
			8
			9
			10
			11
			12
			13
			14
			15
			16
			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	04/17/2020	End of 2019/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	180,374,369	1,219,549
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	180,597,210	1,219,549
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	14,526,518	
9	(311) Structures and Improvements	89,237,846	1,946,944
10	(312) Boiler Plant Equipment	161,752,233	189,582
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	130,100,964	1,146,121
13	(315) Accessory Electric Equipment	83,852,557	2,458,209
14	(316) Misc. Power Plant Equipment	51,278,827	4,199,647
15	(317) Asset Retirement Costs for Steam Production	109,537	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	530,858,482	9,940,503
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	226,796	
38	(341) Structures and Improvements	23,574,789	134,960
39	(342) Fuel Holders, Products, and Accessories	21,995,712	283,361
40	(343) Prime Movers	106,198,845	
41	(344) Generators	362,508,178	-55,958
42	(345) Accessory Electric Equipment	33,389,503	
43	(346) Misc. Power Plant Equipment	30,722,526	2,466,275
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	578,616,349	2,828,638
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,109,474,831	12,769,141

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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	239,239,708	3,789,218
49	(352) Structures and Improvements	599,716,718	37,954,759
50	(353) Station Equipment	1,817,621,789	105,950,833
51	(354) Towers and Fixtures	901,633,077	5,598,652
52	(355) Poles and Fixtures	611,303,688	140,390,279
53	(356) Overhead Conductors and Devices	661,523,013	68,434,341
54	(357) Underground Conduit	459,481,883	20,032,963
55	(358) Underground Conductors and Devices	520,562,557	453,155
56	(359) Roads and Trails	320,923,164	8,189,383
57	(359.1) Asset Retirement Costs for Transmission Plant	1,492,188	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	6,133,497,785	390,793,583
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	105,490,899	2,262,152
61	(361) Structures and Improvements	9,338,052	581,970
62	(362) Station Equipment	554,684,952	54,139,783
63	(363) Storage Battery Equipment	124,355,578	3,226,825
64	(364) Poles, Towers, and Fixtures	777,112,872	91,079,561
65	(365) Overhead Conductors and Devices	761,301,825	92,713,961
66	(366) Underground Conduit	1,340,502,110	70,776,017
67	(367) Underground Conductors and Devices	1,635,258,486	91,625,394
68	(368) Line Transformers	681,710,678	39,905,750
69	(369) Services	543,611,609	42,011,878
70	(370) Meters	257,405,572	9,487,852
71	(371) Installations on Customer Premises	9,429,492	325,622
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	32,118,576	833,842
74	(374) Asset Retirement Costs for Distribution Plant	27,972,003	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,860,292,704	498,970,607
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	45,486,085	125,561
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	58,146	
90	(393) Stores Equipment	46,522	
91	(394) Tools, Shop and Garage Equipment	34,310,474	1,547,541
92	(395) Laboratory Equipment	5,333,954	
93	(396) Power Operated Equipment	60,529	
94	(397) Communication Equipment	312,796,340	21,687,672
95	(398) Miscellaneous Equipment	23,844,466	41,415,945
96	SUBTOTAL (Enter Total of lines 86 thru 95)	429,248,659	64,776,719
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)	429,248,659	64,776,719
100	TOTAL (Accounts 101 and 106)	14,713,111,189	968,529,599
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)	14,713,111,189	968,529,599

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	04/17/2020	End of 2019/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
5,076,805	-979,446	1,352,415	176,890,082		4
5,076,805	-979,446	1,352,415	177,112,923		5
					6
					7
			14,526,518		8
			91,184,790		9
			161,941,815		10
					11
			131,247,085		12
			86,310,766		13
		-3,544	55,474,930		14
			109,537		15
		-3,544	540,795,441		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			226,796		37
			23,709,749		38
			22,279,073		39
			106,198,845		40
	-190,659		362,261,561		41
			33,389,503		42
		3,544	33,192,345		43
					44
	-190,659	3,544	581,257,872		45
	-190,659		1,122,053,313		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	04/17/2020	End of 2019/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
		-2,700	243,026,226		48
467,742	-6,082,870	846,544	631,967,409		49
4,682,518	-8,757,885	-2,654,684	1,907,477,535		50
	-1,397,507		905,834,222		51
4,668,941			747,025,026		52
5,061,267			724,896,087		53
392,680		-11,661,300	467,460,866		54
		-15,149,700	505,866,012		55
		-186,300	328,926,247		56
	-1,954,901		-462,713		57
15,273,148	-18,193,163	-28,808,140	6,462,016,917		58
					59
			107,753,051		60
27,246			9,892,776		61
1,549,307	-2,248,566	813,643	605,840,505		62
			127,582,403		63
9,240,238	561,147	-1,909,118	857,604,224		64
3,610,609	346,525		850,751,702		65
3,400,172	-45,415		1,407,832,540		66
8,399,624	39,128		1,718,523,384		67
3,153,535	251,117		718,714,010		68
1,847,635	-3,241		583,772,611		69
239,620			266,653,804		70
21,888			9,733,226		71
					72
82,769			32,869,649		73
	-5,317,217		22,654,786		74
31,572,643	-6,416,522	-1,095,475	7,320,178,671		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			7,312,143		86
			45,611,646		87
					88
			58,146		89
			46,522		90
489,164			35,368,851		91
			5,333,954		92
			60,529		93
47,932	-838,969	2,901,498	336,498,609		94
58,944			65,201,467		95
596,040	-838,969	2,901,498	495,491,867		96
					97
					98
596,040	-838,969	2,901,498	495,491,867		99
52,518,636	-26,618,759	-25,649,702	15,576,853,691		100
					101
					102
					103
52,518,636	-26,618,759	-25,649,702	15,576,853,691		104

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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Reclassification of 2019 Electric Plant-in-Service for Ratemaking
Plant in Service Classified under FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	BOY 2019	EOY 2019
Intangible Plant	180,374,368	176,890,080
Steam Production Plant	545,574,127	556,350,443
Nuclear Production Plant	-	-
Other Production Plant	522,513,934	524,898,411
Transmission Plant	6,051,311,848	6,372,653,581
Distribution Plant	6,940,409,503	7,414,162,678
General Plant	429,248,656	495,491,863
Ratemaking Electric	14,669,432,436	15,540,447,056
ASC 410 (FAS 143 and FIN 47)	29,573,728	22,301,610
Cuyamaca Permanent Adjustment	14,105,025	14,105,025
Total Electric Plant-in-Service	14,713,111,189	15,576,853,691

Total 13-Month Average Plant Balance for 2019 - Steam Production	549,685,714
Total 13-Month Average Plant Balance for 2019 - Nuclear Production	0
Total 13-Month Average Plant Balance for 2019 - Other Production	523,339,623
Total 13-Month Average Plant Balance for 2019 - Transmission Plant	6,183,368,550

* As a result of the SONGS plant closure, the December 2019 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	04/17/2020	End of 2019/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	30 Mile-500KV Transmission Line	ER12-	07/02/2042	85,194,000
2		(Border-East Line)	686-000		
3					
4	Citizens Sycamore-Penasquitos	11.5 Mile-Underground 230KV	ER19-1513-	06/01/2049	27,000,000
5	Transmission LLC	Transmission Line (Segment B)	000 & ER19		
6			1513-001		
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				112,194,000

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	04/17/2020	End of 2019/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			0

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2020	2019/Q4

FOOTNOTE DATA

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

The 13-Month Average Electric Transmission Plant Held for Future Use is $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	04/17/2020	End of 2019/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	PALOMAR ENERGY CENTER OPERATIONAL ENHANCEMENTS	1,759,511
2	CUYAMACA PEAK ENERGY PLANT	2,616,760
3	TL628 CABLE REPLACEMENT	1,098,491
4	TL698 CABLE REPLACEMENT	1,123,663
5	TL6916 POLE REPLACEMENT	1,191,021
6	SAN MARCOS SUB REBUILD 69KV & 12 KV	1,234,830
7	SOUTHWEST POWERLINK HIGH VOLTAGE CONVERSION	1,294,028
8	TL13831 WOOD TO STEEL REPLACEMENT	1,307,880
9	TL694 WOOD TO STEEL REPLACEMENT	1,373,128
10	SUBSTATION SECURITY PROJECTS UNDER $500K	1,435,902
11	TL698 WOOD TO STEEL REPLACEMENT	1,455,395
12	TL636 WOOD POLE REPLACEMENT	1,725,803
13	TL600 RELIABILITY POLE REPLACEMENTS	1,757,805
14	TL667 CABLE REPLACEMENT	1,779,183
15	SUBSTATION AUXILIARY POWER SYSTEMS	2,011,076
16	GRANITE SUBSTATION 69KV LOOP-IN	2,099,187
17	POWAY SUBSTATION REBUILD	2,373,990
18	TL603B SWEETWATER TAP REMOVAL	2,416,484
19	TL692 WOOD TO STEEL REPLACEMENT	2,561,827
20	SYCAMORE-PENASQUITOS NEW 230KV TIE LINE	2,717,915
21	GATEWAY ENERGY STORAGE PROJECT	2,973,464
22	2ND 69KV LINE POMERADO TO POWAY	3,185,860
23	SUNCREST SUBSTATION - RENEWABLE INTERCONNECTIONS	3,187,067
24	OVERSTRESSED BREAKER REPLACEMENTS	3,444,657
25	AERIAL MARKING FOR SAFETY	3,520,228
26	TL686 WARNERS-NARROWS POLE REPLACEMENT	3,681,847
27	TL674A RECONFIGURE	3,972,570
28	WARNER SUBSTATION 69KV RELAY UPGRADES	4,040,621
29	TL664 SOUTHBAY-SWEETWATER UPGRADE	4,083,594
30	DESCANSO SUBSTATION CONTROL & PROTECTION REPLACEMENT	4,141,926
31	TL691 WOOD TO STEEL REPLACEMENT	4,216,369
32	HELICOPTER ACCESS FOR TRANSMISSION STRUCTURES	4,536,822
33	TL6975 ESCONDIDO - SAN MARCOS	4,667,540
34	TRANSMISSION SYSTEM AUTOMATION	4,961,721
35	MIGUEL SUB 230KV REBUILD	5,300,610
36	TL690 WOOD TO STEEL REPLACEMENT	5,345,139
37	TL673 CABLE REPLACE	6,046,677
38	TL695 SW POLE REPLACEMENT	6,751,719
39	TRANSMISSION SUBSTATION PROJECTS UNDER $500K	6,772,008
40	TL615/659 CABLE REPLACEMENT	7,144,426
41	TL6912 WOOD TO STEEL REPLACEMENT	7,333,006
42	TL6906 MESA RIM LOOP-IN	7,748,493
43	TOTAL	1,129,880,014

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	04/17/2020	End of 2019/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	TL676 MISSION - MESA HEIGHTS RECONDUCTOR	7,935,465
2	SUBSTATION RELIABILITY UPGRADE PROJECT	7,981,325
3	TL6926 RINCON-VALLEY CENTER POLE REPLACEMENT	10,075,709
4	CONDITION BASED MONITORING - CIRCUIT BREAKERS	10,533,005
5	AVOCADO SUB 69KV REBUILD	10,892,018
6	SYNCHRONIZED PHASOR MEASUREMENT SYSTEM	11,274,648
7	MERCHANT SWITCHYARD	15,605,217
8	TL23001 SAN LUIS REY TO MISSION	18,666,395
9	MISSION 230KV REBUILD	19,056,177
10	TRANSMISSION PROJECTS UNDER $500K	22,289,563
11	CRITICAL ASSET SECURITY	22,474,040
12	TRANSMISSION INFRASTRUCTURE IMPROVEMENTS	23,201,263
13	FIBER OPTIC FOR RELAY PROTECTION & TELECOMMUNICATION	27,046,699
14	TL649 POLE REPLACEMENT	28,591,243
15	ARTESIAN 230KV SUBSTATION EXPANSION	29,495,511
16	TL663 MISSION-KEARNY RECONDUCTOR	39,066,081
17	TL633 RECONDUCTOR	47,602,994
18	ORANGE COUNTY LONG RANGE PLAN	148,863,651
19	CLEVELAND NATIONAL FOREST POLE REPLACEMENTS	203,820,106
20	PURE WATER	2,519,684
21	TEE MODERNIZATION PROGRAM	1,012,120
22	4KV MODERNIZATION	1,141,991
23	GAS INSULATED SWITCH REPLACEMENT	1,268,684
24	HFTD FUSE REPLACEMENTS	1,283,986
25	ELECTRIFY LOCAL HIGHWAYS	1,286,165
26	DOE SWITCH REPLACEMENT	1,330,411
27	DISTRIBUTION SYSTEM CAPACITY IMPROVEMENT	1,337,607
28	REACTIVE SMALL CAPITAL PROJECTS	1,337,712
29	WIRELESS FAULT INDICATORS	1,357,519
30	OH NON-RESIDENTIAL NEW BUSINESS	1,421,447
31	UG DISTRIBUTION SERVICE MANAGEMENT	1,458,852
32	DISTRIBUTION SUBSTATION RELIABILITY	1,490,558
33	PSPS ENGINEERING ENHANCEMENTS	1,895,416
34	AB2868 ENERGY STORAGE	2,300,593
35	SAN MATEO SUB REBUILD	2,801,148
36	CORRECTIVE MAINTENANCE PROGRAM	2,877,395
37	NEW BUSINESS INFRASTRUCTURE	2,917,483
38	OBSOLETE SUBSTATION EQUIPMENT REPLACEMENT	2,946,015
39	SOCRE – DISTRIBUTION IN HFTD	3,279,327
40	MID-COAST TROLLEY EXTENSION PROJECT	3,313,181
41	CORRECTIVE MAINT. PROG. (CMP) UG SWITCH REPLAC. & MANHOLE REPAIR	3,504,445
42	UG NON-RESIDENTIAL NEW BUSINESS	3,520,665
43	TOTAL	1,129,880,014

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	04/17/2020	End of 2019/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	NEW SERVICE INSTALLATIONS	3,521,901
2	OH DISTRIBUTION SERVICE MANAGEMENT	4,536,634
3	SUBSTATION BREAKER AND RELAY REPLACEMENTS	4,923,117
4	WIRE SAFETY ENHANCEMENT (WISE)	5,020,194
5	STREAMVIEW SUBSTATION 69/12KV REBUILD	5,359,815
6	UG RESIDENTIAL NEW BUSINESS	5,562,776
7	ELECTRIC DISTRIBUTION STREET & HIGHWAY RELOCATIONS	6,813,307
8	WOOD POLE REINFORCEMENT	8,271,126
9	RANCHO SANTA FE SUBSTATION FIRE HARDENING	8,349,202
10	SCADA CONTROL PANEL REPLACEMENT	9,254,344
11	HFTD TIER 2 & 3 CMP POLE REPLACEMENTS	10,636,573
12	FIRE THREAT ZONE PROTECTION & SCADA UPGRADE	10,716,705
13	CITY OF SAN DIEGO SURCHARGE PROGRAM	11,960,302
14	MOBILE HOME PARK UTILITY UPGRADES	14,240,281
15	POLE RISK MITIGATION	18,514,998
16	MIRAMAR ENERGY STORAGE	23,115,745
17	CONVERSION FROM OH TO UG RULE 20A	27,678,702
18	STRATEGIC FIRE HARDENING	63,616,202
19	IT - ENTERPRISE - APPLICATION - OPS SUPPORT- R	5,349,379
20	IT - ENTERPRISE - NETWORK - OPS SUPPORT - R	6,069,225
21	UNALLOCATED CONSTRUCTION OVERHEADS & LABOR ACCRUAL	-40,651,223
22	MINOR PROJECTS (LESS THAN $1,000,000)	22,556,952
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,129,880,014

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	04/17/2020	End of 2019/Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,795,427,296	4,775,492,331		19,934,965
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	508,740,348	508,740,348		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others	3,099,198			3,099,198
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)	511,839,546	508,740,348		3,099,198
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	47,441,831	47,441,831		
13	Cost of Removal	75,082,989	75,082,989		
14	Salvage (Credit)	924,304	924,304		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	121,600,516	121,600,516		
16	Other Debit or Cr. Items (Describe, details in footnote):	109,403,200	109,403,200		
17					
18	Book Cost or Asset Retirement Costs Retired	-104,783,346	-104,783,346		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,190,286,180	5,167,252,017		23,034,163
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	250,440,582	250,440,582		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	290,452,827	290,452,827		
25	Transmission	1,332,256,509	1,309,222,346		23,034,163
26	Distribution	3,133,015,736	3,133,015,736		
27	Regional Transmission and Market Operation				
28	General	184,120,526	184,120,526		
29	TOTAL (Enter Total of lines 20 thru 28)	5,190,286,180	5,167,252,017		23,034,163

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

Depreciation Provision - Electric Only (Line 10, Pg 219)	$	508,740,348
Depreciation Provision - Common Alloc. to Elec. (Line 11, Pg 336)		38,502,870
Depreciation Provision - (Line 6, Col. G, Pg 115)	$	547,243,218

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

Book Cost of Plant Retired (Line 12, Col. B, Pg 219)	$	(47,411,831)
Total Plant Retired (Line 100, Col. D, Pg 207)		52,518,636
Adj. For Land & Intangible Retirements not impacting A/C 108		(5,076,805)
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)	$	108,472,307
Transfer of Reserve Balances between Departments		930,893
Other Debit and Credit Items (Line 16, Pg 219)	$	109,403,200

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

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
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
				42

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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)			
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)	126,655,809	122,595,800	ELECTRIC/GAS
6	Assigned to - Operations and Maintenance	9,180,129	8,885,855	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)	367,750	355,961	ELECTRIC/GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	136,203,688	131,837,616	
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)	136,203,688	131,837,616	

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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Reclassification of FERC Form 1 2019 Materials & Supplies, Page 227, for Ratemaking

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

	EOY 2019
Total Materials and Supplies (FERC 154)	131,837,616 [1]
As Assigned to Department for Ratemaking	
Electric Department	127,133,879
Gas Department	4,703,737
Total Allowable Materials and Supplies per FERC Formula	127,133,879
Total 13-Month Average Electric M&S for 2019	128,028,387 [2]

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

[2] Ties to Line 1 of Cost Statement AL supporting workpaper, in TO5 Cycle 3 FERC Filing.

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	04/17/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	118,746.00			
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	Transfers to Palomar	-3.00			
10	Transfers to Desert Star	-3.00			
11					
12					
13					
14					
15	Total	-6.00			
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	131,687.00		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	04/17/2020	End of 2019/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.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						118,746.00		1
								2
								3
12,947.00		12,947.00		349,569.00		401,357.00		4
								5
								6
								7
								8
						-3.00		9
						-3.00		10
								11
								12
								13
								14
						-6.00		15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
12,947.00		12,947.00		349,569.00		520,097.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								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	04/17/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 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				

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.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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	Sycamore-Bernardo Project	1,366,481		107	-1,366,481	
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	1,366,481			-1,366,481	

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					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
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	04/17/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Taxes Recoverable in Rates	766,581,194	173,654,425	Various	110,959,735	829,275,884
2	Amortized Over Various Lives					
3						
4	Employer's Accounting for Postemployment Benefits	5,358,000		228	829,000	4,529,000
5						
6	Environmental Clean-Up	5,031,340	3,167,660	242/253	3,108,831	5,090,169
7						
8	Balancing Account Undercollections	509,656,804	415,878,583			925,535,387
9						
10	Pension Benefits	187,884,975		228	65,791,979	122,092,996
11						
12	SONGS Mitigation	22,598,921	17,085,625			39,684,546
13						
14	Electric Derivatives	136,613,475	5,814,363	175/244	32,654,615	109,773,223
15						
16	Contribution to City of Escondido	1,202,918		253	146,043	1,056,875
17	(20 year life, starting 2006)					
18						
19	Asset Retirement Obligations	18,519,319	6,315,781	Various	506,452	24,328,648
20						
21	Sunrise Wildfire Mitigation	119,820,106	852,888			120,672,994
22						
23	Beyond The Meter	20,410,986	9,759,896	232	2,866,296	27,304,586
24						
25	Unamortized Line of Credit (LOC) Net	687,685		930	687,685	
26						
27	Theoretical Withdrawal Premium OIL	15,997,255		253	3,340,448	12,656,807
28						
29	Post Retirement Benefits Other than Pension		439,015			439,015
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,810,362,978	632,968,236		220,891,084	2,222,440,130

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	04/17/2020	End of 2019/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	632,604	584,394	181, 428	397,502	819,496
2						
3	Southwest Powerlink Deferred	316,522		406	15,744	300,778
4	per CPUC					
5	(amortization 1/1986 - 12/2023)					
6						
7	Mitigation Fund	137,706				137,706
8						
9	Environmental Program	5,941,270	1,075,456	various	140,051	6,876,675
10						
11	Workers Comp Receivable	8,997,018	2,607,945	various	631,442	10,973,521
12						
13	SONGS Decommissioning	313,828	16,216,989	228	15,851,727	679,090
14						
15	Pendleton Energy Park	195,734				195,734
16						
17	Gaskell Tax Equity	115,312		various	115,312	
18						
19	Supervisory Control & Data	498,664				498,664
20	Acquisition Equipment					
21						
22	SONGS Reg Asset Receivable	84,054,297		143	36,248,478	47,805,819
23						
24	PBOP Asset	2,290,331	19,025,808	254	1,682,299	19,633,840
25						
26	Surplus Material	4,720,675	68,985	163	-533,743	5,323,403
27						
28	Airbus Helicopter Trade Account	462,000				462,000
29						
30	Wildfire Fund AB1054		806,952,593	various	415,132,124	391,820,469
31						
32	Real Estate Operating Lease	27,069		various	27,069	
33						
34	Miscellaneous Other	134,315	22,791	various	3,622	153,484
35						
36						
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	108,837,345				485,680,679

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	04/17/2020	End of 2019/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	73,102,522	89,070,415
3	State	66,258,760	44,735,614
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	139,361,282	133,806,029
9	Gas		
10	Federal	5,163,527	6,201,175
11	State	2,326,155	3,249,674
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	7,489,682	9,450,849
17	Other (Specify) Non-Utiltity	409,639	410,784
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	147,260,603	143,667,662

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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Account 190 electric balance at the beginning of the year reflects amortization of transmission related excess deferred federal income taxes in the amount of $1,232,000.

Account 190 non-Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the beginning of the year was ($233,360,930).

Account 190 Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the beginning of the year was ($12,026,401).

Account 190 transmission related other deferred tax (asset) included in electric accumulated deferred income taxes at the beginning of the year was ($2,141,800).

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

Account 190 electric balance at the end of the year reflects amortization of transmission related excess deferred federal income taxes in the amount of $1,292,000.

Account 190 non-Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($227,471,476).

Account 190 Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($11,722,884).

Account 190 transmission related other deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($1,787,644).

The deferred tax asset related to FERC transmission on a stand-alone basis as of December 31, 2019 and 2018 is reflected in the table below:

STANDALONE FERC TRANSMISSION NET OPERATING LOSS DEFERRED TAX ASSET (1)
(Dollars in millions)

	Years ended December 31,			
		2019		2018
FERC AC 190				
FERC - Remeasured Amount	$	119	$	124
FERC - Excess Reserve Protected	$	108	$	109
FERC - Excess Reserve Unprotected	$	0	$	0
Total	$	227	$	233

(1) Does not include any amounts related to Citizens.

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	04/17/2020	End of 2019/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				
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				

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
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

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	04/17/2020	End of 2019/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	79,665,368
9	Equity infusion from Enova Corporation	400,000,000
10	Wildfire Fund AB1054 initial contribution from Enova Corporation	322,500,000
11	Total Account 211	802,165,368
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	802,165,368

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	04/17/2020	End of 2019/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		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
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	04/17/2020	End of 2019/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	6.125% Series FFF due 2037	250,000,000	2,556,327
21			780,000 D
22	6.000% Series GGG due 2039	300,000,000	3,057,571
23			1,380,000 D
24	5.350% Series HHH due 2040	250,000,000	2,486,955
25			335,000 D
26	4.500% Series III due 2040	500,000,000	5,044,008
27			5,515,000 D
28	3.000% Series JJJ due 2021	350,000,000	2,775,568
29			1,795,500 D
30	3.950% Series LLL due 2041	250,000,000	2,639,787
31			350,000 D
32	4.300% Series MMM due 2042	250,000,000	2,569,738
33	TOTAL	5,301,265,000	75,130,042

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	04/17/2020	End of 2019/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			1,297,500 D
2	3.600% Series NNN due 2023	450,000,000	3,670,004
3			72,000 D
4	1.914% Series PPP due 2022	250,000,000	725,420
5			
6	2.500% Series QQQ due 2026	500,000,000	4,279,086
7			1,625,000 D
8	3.750% Series RRR due 2047	400,000,000	4,038,478
9			1,784,000 D
10	4.150% Series SSS due 2048	400,000,000	4,072,043
11			1,768,000 D
12	4.100% Series TTT due 2049 (D.15-08-011 and	400,000,000	4,345,931
13	D.18-02-012 issued May 31, 2019)		420,000 D
14	TOTAL ACCOUNT 221	5,301,265,000	75,130,042
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	5,301,265,000	75,130,042

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
						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
09/20/07	09/15/37	09/20/07	09/15/37	250,000,000	15,312,500	20
						21
05/14/09	06/01/39	05/14/09	06/01/39	300,000,000	18,000,000	22
						23
05/13/10	05/15/40	05/13/10	05/15/40	250,000,000	13,375,000	24
						25
08/26/10	08/15/40	08/26/10	08/15/40	500,000,000	22,500,000	26
						27
08/18/11	08/15/21	08/18/11	08/15/21	350,000,000	10,500,000	28
						29
11/17/11	11/15/41	11/17/11	11/15/41	250,000,000	9,875,000	30
						31
03/22/12	04/01/42	03/22/12	04/01/42	250,000,000	10,750,000	32
				5,140,552,000	213,846,544	33

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
09/09/13	09/01/23	09/09/13	09/01/23	450,000,000	16,200,000	2
						3
03/12/15	02/01/22	03/12/15	02/01/22	89,287,000	1,936,809	4
						5
05/19/16	05/15/26	05/19/16	05/15/26	500,000,000	12,500,000	6
						7
06/08/17	06/01/47	06/08/17	06/01/47	400,000,000	15,000,000	8
						9
05/17/18	05/15/48	05/17/18	05/15/48	400,000,000	16,600,000	10
						11
05/31/19	06/15/49	5/31/19	06/15/49	400,000,000	9,566,667	12
						13
				5,140,552,000	213,846,544	14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				5,140,552,000	213,846,544	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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Expense	$56,595,542
Discount	$18,534,500
Account 221	$75,130,042

Schedule Page: 256.1 Line No.: 16 Column: a

D.93-09-069 - At December 2019 total remaining authority for new preferred debt under this decision was $48,360,000.

D.04-01-009 - At December 2019 total remaining authority for new preferred debt under this decision was $4,000,000 and $76,000,000 for rollover preferred.

D.06-05-015 - At December 2019 total remaining authority for new preferred debt under this decision was $200,000,000.

D.10-10-023 - At December 2019 total remaining authority for new preferred debt under this decision was $150,000,000.

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 and $300,000,000 in rollover debt. In May 2019, SDG&E issued 4.1000% First Mortgage bond series TTT for $66,630,000 due 2049. At December 2019 total remaining authority for rollover debt under this decision was $121,930,000.

D.18-02-012 - In February 2018, SDG&E received authority from the California Public Utilities Commission to issue $750,000,000 of new debt and $300,000,000 in rollover debt. In May 2019, SDG&E issued 4.1000% First Mortgage bond series TTT for $333,370,000 due 2049. At December 2019 total remaining authority for new debt under this decision was $416,630,000 and $300,000,000 for rollover debt.

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	04/17/2020	End of 2019/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)	769,183,643
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	57,269,585
6	Other (Itemized within footnote)	157,000
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation on Fixed Assets	722,502,427
11	Federal and State Taxes	170,684,202
12	Amortization and Interest Capitalized	71,824,207
13	Other (Itemized within footnote)	20,561,135
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	-75,375,412
16	Deferred Construction Revenue	-6,825,012
17	SONGS Decommissioning Costs	-15,190,000
18	Other (Itemized within footnote)	-7,288,877
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation on Fixed Assets	-587,453,360
21	Regulatory Balancing Accounts	-208,482,501
22	Percentage Repair Allowance	-172,339,471
23	Current State Tax Deduction	-31,125,419
24	Software Development Costs	-123,593,576
25	Removal Costs	-90,310,109
26	Other (Itemized within footnote)	-29,661,179
27	Federal Tax Net Income	464,537,285
28	Show Computation of Tax:	
29	Federal Tax @ 21%	97,552,830
30	Deferred Taxes	51,428,601
31	Tax Credits and Other Adjustments (net)	-9,608,538
32	Fed Discrete Taxes	-31,203,687
33	Total Federal Income Tax Expense	108,169,206
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
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	04/17/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 6 Column: b

Fuel Tax Credit Addback	$ 157,000
	157,000

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

Bad Debt	$ 485,966
Fringe Benefits	1,744,281
Meals & Entertainment	2,317,642
Contingency Book Reserves	3,210,449
Miscellaneous Expenses	4,784,363
Restricted Stock	8,018,434
	$ 20,561,135

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

South Georgia Adjustment of $1,347,000 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.: 18 Column: b

Book Gain on Sale of Utility Property	$ (556,893)
Keyman Life Insurance	(6,732,058)
	$ (7,288,877)

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

SERP	$ 226,715
Miscellaneous Expenses	(151,413)
Abandonment Loss	(438,916)
Stock Options	(530,806)
Deferred Credits	(575,263)
Property Tax / Ad Valorem	(4,943,750)
Facts & Circumstances Repairs	(23,247,746)
	$ (29,661,179)

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	04/17/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	LOCAL:					
2	Ad Valorem (Note 1)		1,425,576	143,259,054	157,328,900	-14,060,845
3	Sales and Use (Note 2)	14,707		334,098	321,987	
4	Business License			47,799	47,799	
5						
6	SUBTOTAL	14,707	1,425,576	143,640,951	157,698,686	-14,060,845
7						
8	STATE:					
9	Franchise (Note 3)	8,066,390		31,158,925	50,155,087	28,436,396
10	Unemployment (Note 4)	530,004		363,042	891,574	
11	Sales and Use (Note 2)	22,966		1,145,476	1,103,953	
12	Fuel Tax	8,942		26,858	26,526	
13						
14	SUBTOTAL	8,628,302		32,694,301	52,177,140	28,436,396
15						
16	FEDERAL:					
17	Taxes on Income (Note 3)	19,722,744		34,234,237	140,835,907	95,979
18	Retirement (Note 4)	1,135,444		27,996,829	28,818,397	
19	Unemployment (Note 4)	105,964		96,508	202,088	
20	Medicare (Note 4)	265,546		8,047,607	8,168,046	
21	Fuel Tax		97,774	39,693	127,718	
22						
23						
24	SUBTOTAL	21,229,698	97,774	70,414,874	178,152,156	95,979
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	29,872,707	1,523,350	246,750,126	388,027,982	14,471,530

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
	1,434,577	124,526,615			18,732,439	2
26,818					334,098	3
		43,864			3,935	4
						5
26,818	1,434,577	124,570,479			19,070,472	6
						7
						8
	39,366,168	36,785,557			-5,626,632	9
1,472		270,637			92,404	10
64,489					1,145,476	11
9,274					26,858	12
						13
75,235	39,366,168	37,056,194			-4,361,894	14
						15
						16
	86,974,905	49,576,298			-15,342,061	17
313,876		9,988,579			18,008,249	18
384		71,943			24,564	19
145,107		2,871,551			5,176,055	20
	9,749				39,693	21
						22
						23
459,367	86,984,654	62,508,371			7,906,500	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
561,420	127,785,399	224,135,044			22,615,078	41

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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

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

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

Property tax expense of $632,254 and $67,128 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines are deducted and moved to column (l).

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

Includes property tax expense of $632,254 and $67,128 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines.

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

Description	Adjustment Amount	FERC 190	FERC 283	FERC 171	FERC 237
Balance Sheet Reclassification Due to FIN 48 Liabilities	28,436,396	(28,436,396)			
Total - California Corporation Franchise Tax Adjustment	28,436,396	(28,436,396)	-	-	-

Schedule Page: 262 Line No.: 17 Column: f

Description	Adjustment Amount	FERC 190	FERC 283	FERC 171	FERC 237
Utilization of Net Operating Loss					
Balance Sheet Reclassification Due to FIN 48 Liabilities	95,979		(95,979)		
Balance Sheet Reclassification Due to FIN 48 Liabilities - Interest					
Total - Federal Income Tax Adjustment	95,979	-	(95,979)	-	-

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

Payroll tax expense of $21,778 and $2,438 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines are deducted and moved to column (l).

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

Includes payroll tax expense of $21,778 and $2,438 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines.

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.

Sales and Use tax adjustments in column "f" are to adjust carry forward balances from last year.

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	04/17/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Various	14,148,617			411.4	986,264	
7							
8	TOTAL	14,148,617				986,264	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility Various	1,474,501			411.4	208,505	
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

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
13,162,353	25 to 30 years		6
			7
13,162,353			8
			9
1,265,996	25 to 30 years		10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Account 255 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	04/17/2020	End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	CIAC/CAC Tax Gross-Ups	62,076,100	456/495	13,688,708	15,331,313	63,718,705
2	Amortized over various 31 yr lives					
3						
4	SONGS Mitigation	18,761,619	182.3	1,087,252	21,136,439	38,810,806
5						
6	OII Insurance Limited	15,997,254		3,340,448		12,656,806
7						
8	Sunrise Fire Mitigation Liability	116,316,277	182.3	3,573,905	4,356,717	117,099,089
9						
10	Citizens Lease	64,027,787	242	64,650,463	87,651,265	87,028,589
11						
12	Greenhouse Gas Obligations	30,201,710	158	15,375,888	46,906,257	61,732,079
13						
14	Miscellaneous	13,881,839	Various	50,085,015	61,377,629	25,174,453
15						
16	Wildfire Fund			12,900,000	98,762,748	85,862,748
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						
47	TOTAL	321,262,586		164,701,679	335,522,368	492,083,275

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	04/17/2020	End of 2019/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	04/17/2020	End of 2019/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.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

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	04/17/2020	End of 2019/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	1,464,897,859	120,688,880	74,440,028
3	Gas	151,249,709	14,270,784	6,402,606
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,616,147,568	134,959,664	80,842,634
6				
7	Non Utility	35,007,691		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,651,155,259	134,959,664	80,842,634
10	Classification of TOTAL			
11	Federal Income Tax	1,359,566,030	115,608,060	66,947,667
12	State Income Tax	291,589,229	19,351,604	13,894,967
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
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)		
							1
		Various	38,298,521	Various	76,569,332	1,549,417,522	2
		Various	6,697,592	Various	13,668,930	166,089,225	3
							4
			44,996,113		90,238,262	1,715,506,747	5
							6
7,695,342	2,292,019			Various	15,689,431	56,100,445	7
							8
7,695,342	2,292,019		44,996,113		105,927,693	1,771,607,192	9
							10
5,988,436	2,292,019		32,081,923		73,877,309	1,453,718,226	11
1,706,906			12,914,190		32,050,384	317,888,966	12
							13

NOTES (Continued)

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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Account 282 electric balance at the beginning of the year reflects a reduction for (amortization) of non-Citizens transmission related excess deferred federal income taxes in the amount of ($3,654,273).

Account 282 electric balance at the beginning of the year reflects a reduction for (amortization) of Citizens transmission related excess deferred federal income taxes in the amount of ($180,826).

Account 282 non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $661,424,763.

Account 282 Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $12,846,240.

Account 282 non-Citizen transmission related excess deferred income tax reserve at the beginning of the year was $385,497,611.

Account 282 Citizen transmission related excess deferred income tax reserve at the beginning of the year was $8,679,665.

Schedule Page: 274 Line No.: 3 Column: k

Account 282 electric balance at the end of the year reflects a reduction for (amortization) of non-Citizens transmission related excess deferred federal income taxes in the amount of ($4,566,795).

Account 282 electric balance at the end of the year reflects a reduction for (amortization) of Citizens transmission related excess deferred federal income taxes in the amount of ($180,826).

Account 282 non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $720,245,325.

Account 282 Citizens Sunrise transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $12,485,206.

Account 282 Citizens SX-PQ transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $2,872,340.

Account 282 non-Citizen transmission related excess deferred income tax reserve at the end of the year was $380,930,817.

Account 282 Citizen transmission related excess deferred income tax reserve at the end of the year was $8,498,838.

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	04/17/2020	End of 2019/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		54,809,122	72,185,352	33,441,280
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	54,809,122	72,185,352	33,441,280
10	Gas			
11		1,454,448	7,408,484	-4,261,989
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	1,454,448	7,408,484	-4,261,989
18	Non-Utilities	24,568,726		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	80,832,296	79,593,836	29,179,291
20	Classification of TOTAL			
21	Federal Income Tax	56,182,943	55,555,942	36,549,077
22	State Income Tax	24,649,353	24,037,894	-7,369,786
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) 04/17/2020	Year/Period of Report End of 2019/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
		Various	44,307,024	Various	122,431,736	171,677,906	3
							4
							5
							6
							7
							8
			44,307,024		122,431,736	171,677,906	9
							10
		Various	9,305,887	Various	11,687,035	15,506,069	11
							12
							13
							14
							15
							16
			9,305,887		11,687,035	15,506,069	17
69,476	581,368	Various	286,937	Various	6,379,712	30,149,609	18
69,476	581,368		53,899,848		140,498,483	217,333,584	19
							20
59,570	409,756		36,872,926		111,228,279	149,194,975	21
9,906	171,612		17,026,923		29,270,205	68,138,609	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: b

Account 283 electric balance at the beginning of the year reflects a reduction for amortization of transmission related excess deferred federal income taxes in the amount of $2,559,000.

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the beginning of the year was $5,328,251.

Schedule Page: 276 Line No.: 3 Column: k

Account 283 electric balance at the end of the year reflects a reduction for (amortization) of transmission related excess deferred federal income taxes in the amount of $0.

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the end of the year was $5,987,514.

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	04/17/2020	End of 2019/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	1,002,083,980	Various	82,373,160	17,600,752	937,311,572
3						
4						
5	Asset Retirement Obligations	468,734,407	230	6,867,737	123,457,316	585,323,986
6						
7						
8	Balancing Account Overcollections	541,299,387	456/495	33,822,275	326,927,531	834,404,643
9						
10						
11	Electric / Gas Derivatives	286,947,244	175.1	184,949,976	91,127	102,088,395
12						
13						
14	PBOP Benefits	2,290,331			17,343,509	19,633,840
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	2,301,355,349		308,013,148	485,420,235	2,478,762,436

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	04/17/2020	End of 2019/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	1,456,233,480	1,603,852,935
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,478,133,425	1,519,500,355
5	Large (or Ind.) (See Instr. 4)	394,124,985	402,970,619
6	(444) Public Street and Highway Lighting	14,246,864	14,942,475
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,342,738,754	3,541,266,384
11	(447) Sales for Resale	389,753,137	562,100,549
12	TOTAL Sales of Electricity	3,732,491,891	4,103,366,933
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	3,732,491,891	4,103,366,933
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	99,652,448	100,348,353
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,223,519	5,791,140
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	504,297,960	98,905,972
22	(456.1) Revenues from Transmission of Electricity of Others	302,746,348	256,061,609
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	911,920,275	461,107,074
27	TOTAL Electric Operating Revenues	4,644,412,166	4,564,474,007

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
5,981,976	6,336,436	1,298,976	1,290,690	2
				3
6,294,640	6,539,118	150,666	151,082	4
2,052,235	2,182,924	421	435	5
76,956	80,533	2,074	2,059	6
				7
				8
				9
14,405,807	15,139,011	1,452,137	1,444,266	10
9,822,599	11,199,395			11
24,228,406	26,338,406	1,452,137	1,444,266	12
				13
24,228,406	26,338,406	1,452,137	1,444,266	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	$ 90,334,917
Net Energy Metering	4,213,988
Service Establishment	3,086,948
Mover Service Charge	744,505
Late Payment Charge	711,561
Other*	560,529
	$ 99,652,448

* Individual balances are less than $250,000

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

Description

San Diego Franchise Fee Surcharge	$ 92,752,428
Service Establishment	3,116,050
Net Energy Metering	2,452,060
Late Payment Charge	721,327
Mover Service Charge	648,933
Other*	657,555
	$100,348,353

* Individual balances are less than $250,000

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

Includes Transmission Revenue Credits of $286,779

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

Includes Transmission Revenue Credits of $1,163,016

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

Description

Direct Access	$ 289,516,742
Cap and Trade Revenues	138,981,178
Balancing Accounts	34,085,211
CCA T&D Revenue	11,214,486
Federal Project Management	10,543,045
PUC Reimbursement Fee	9,790,548
CIAC Income Tax	5,733,677
LCFS Rec Credits	5,126,133
Shared Assets	3,840,189
Generation Trans. Interconnection Rev.	3,762,787
Unbilled Revenue	1,519,000
Litigation	(2,500,000)
Government Turnkey	(9,284,135)
Employee Transfer Fees	579,649
Joint Pole Activity	408,132
Other*	981,318
	$ 504,297,960

* Individual balances are less than $250,000
* Includes Transmission Revenue Credits of $4,811,079

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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Description

Direct Access	$257,483,114
Balancing Accounts	(287,840,406)
Cap and Trade Revenues	101,064,845
Payment Participation	611,145
CIAC Income Tax	5,770,444
Shared Assets	3,269,553
PUC Reimbursement Fee	8,601,335
Government Turnkey	(2,767,917)
Unbilled Revenue	468,000
Joint Pole Activity	3,106,121
Generation Trans. Interconnection Rev.	2,286,377
Affiliation Empl Transfer Fees	1,161,825
Other*	5,691,536
	$ 98,905,972

* Individual balances are less than $250,000
* Includes Transmission Revenue Credits of $3,057,821

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	DR	2,923,136	777,947,671	629,621	4,643	0.2661
2	DRTOU	1,884,634	476,725,959	450,255	4,186	0.2530
3	EVTOU	155,883	33,956,241	16,737	9,314	0.2178
4	DRLI	837,527	130,860,041	196,514	4,262	0.1562
5	DM	36,456	9,505,416	3,398	10,729	0.2607
6	DS	16,202	3,243,727	228	71,061	0.2002
7	DT	126,366	23,249,366	401	315,127	0.1840
8	OL-1	1,545	607,969	1,779	868	0.3935
9	DWL	227	137,090	43	5,279	0.6039
10	Total Residential Sales (440)	5,981,976	1,456,233,480	1,298,976	4,605	0.2434
11						
12	A	54,050	9,766,830	6,875	7,862	0.1807
13	ASTOD	1,784,030	428,083,578	117,914	15,130	0.2400
14	ATOU	205,025	46,092,033	2,608	78,614	0.2248
15	AD	-17	-10,876			0.6398
16	UM	8,838	2,291,390	122	72,443	0.2593
17	PA		-25			
18	PAT1	278,489	46,921,940	3,899	71,426	0.1685
19	AL-TOU	3,843,974	915,224,884	15,164	253,493	0.2381
20	SPSS	893	177,153	4	223,250	0.1984
21	DGAL	42,777	12,180,327	268	159,616	0.2847
22	OL-1	5,023	1,506,952	1,640	3,063	0.3000
23	OLTOU	5,449	1,407,482	101	53,950	0.2583
24	TOUA	66,109	14,491,757	2,071	31,921	0.2192
25	Total Commercial (444)	6,294,640	1,478,133,425	150,666	41,779	0.2348
26						
27	AL-TOU	1,987,627	378,966,826	403	4,932,077	0.1907
28	DG		428,409			
29	A6-TOU	64,608	14,729,750	18	3,589,333	0.2280
30	Total Industrial (442)	2,052,235	394,124,985	421	4,874,667	0.1920
31						
32	LS1	15,676	5,259,101	782	20,046	0.3355
33	LS2	60,072	8,794,229	1,143	52,556	0.1464
34	LS3	1,208	193,534	149	8,107	0.1602
35	Total Public Street and Highway (	76,956	14,246,864	2,074	37,105	0.1851
36						
37						
38						
39						
40						
41	TOTAL Billed	14,405,807	3,342,738,754	1,452,137	9,920	0.2320
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	14,405,807	3,342,738,754	1,452,137	9,920	0.2320

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	California ISO					
2	City of Escondido (Rincon Hydro Plant)	SF	FERC Vol. 10			
3	City of Burbank	SF	FERC Vol. 10			
4	City of Glendale Water and Power	SF	FERC Vol. 10			
5	Citigroup Energy Inc	SF	FERC Vol. 10			
6	Clean Power Alliance of SoCal	SF	FERC Vol. 10			
7	Direct Energy Business Marketing	SF	FERC Vol. 10			
8	EDF Trading North America LLC	SF	FERC Vol. 10			
9	Los Angeles Dept. of Water & Power	SF	FERC Vol. 10			
10	Marin Clean Energy	SF	FERC Vol. 10			
11	Morgan Stanley Capital Group	SF	FERC Vol. 10			
12	Peninsula Clean Energy Authority	SF	FERC Vol. 10			
13	Powerex Corporation	SF	FERC Vol. 10			
14	Sacramento Municipal Utility District	SF	FERC Vol. 10			
	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	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Shell Energy North America (US) LP	SF	FERC Vol. 10			
2						
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	04/17/2020	End of 2019/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.
8,793,899		340,127,281		340,127,281	1
80		13,279		13,279	2
21,600		788,300		788,300	3
800		23,200		23,200	4
24,370		832,296		832,296	5
100,000		770,000	1,540,000	2,310,000	6
270,414		10,931,595	4,294,159	15,225,754	7
	196,099			196,099	8
8,800		284,320		284,320	9
	200,000			200,000	10
115,978		3,020,338		3,020,338	11
427,000		17,163,991	6,419,540	23,583,531	12
4,550		141,025		141,025	13
53,908		2,162,894	808,620	2,971,514	14
0	0	0	0	0	
9,822,599	396,099	376,294,719	13,062,319	389,753,137	
9,822,599	**396,099**	**376,294,719**	**13,062,319**	**389,753,137**	

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	04/17/2020	End of 2019/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.
1,200		36,200		36,200	1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
9,822,599	396,099	376,294,719	13,062,319	389,753,137	
9,822,599	**396,099**	**376,294,719**	**13,062,319**	**389,753,137**	

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 6 Column: j

Contract to sell Renewable Energy Credits

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

Contract to sell Renewable Energy Credits

Schedule Page: 310 Line No.: 12 Column: j

Contract to sell Renewable Energy Credits

Schedule Page: 310 Line No.: 14 Column: j

Contract to sell Renewable Energy Credits

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	04/17/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,153,989	2,323,823
5	(501) Fuel	93,885,412	125,486,426
6	(502) Steam Expenses		10,030
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	301,885	176,593
10	(506) Miscellaneous Steam Power Expenses	6,529,345	6,642,826
11	(507) Rents	37,407	30,174
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	102,908,038	134,669,872
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures	37,981	139,871
17	(512) Maintenance of Boiler Plant	2,646,843	1,742,687
18	(513) Maintenance of Electric Plant	-243,671	748,592
19	(514) Maintenance of Miscellaneous Steam Plant	9,063,286	6,684,017
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,504,439	9,315,167
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	114,412,477	143,985,039
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	176	
25	(518) Fuel		
26	(519) Coolants and Water	310	
27	(520) Steam Expenses	289	
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	4,574,915	2,206,176
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	4,575,690	2,206,176
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	157,983	139,672
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	4,307	370
38	(531) Maintenance of Electric Plant	1,896	
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	164,186	140,042
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	4,739,876	2,346,218
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)		

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	429,983	265,816
63	(547) Fuel	4,056,581	4,523,782
64	(548) Generation Expenses		592
65	(549) Miscellaneous Other Power Generation Expenses	3,670,501	4,318,733
66	(550) Rents	494	2,905
67	TOTAL Operation (Enter Total of lines 62 thru 66)	8,157,559	9,111,828
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	53,995	15,385
71	(553) Maintenance of Generating and Electric Plant	7,041,679	7,950,901
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	6,650,523	6,469,197
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	13,746,197	14,435,483
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	21,903,756	23,547,311
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,731,994,867	1,868,120,739
77	(556) System Control and Load Dispatching	2,767,950	2,899,082
78	(557) Other Expenses	6,496,622	6,336,067
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,741,259,439	1,877,355,888
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,882,315,548	2,047,234,456
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,279,011	6,649,066
84			
85	(561.1) Load Dispatch-Reliability	668,024	543,587
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,351,651	1,623,613
87	(561.3) Load Dispatch-Transmission Service and Scheduling	182,676	228,218
88	(561.4) Scheduling, System Control and Dispatch Services	5,093,244	5,880,423
89	(561.5) Reliability, Planning and Standards Development	94,124	161,160
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	2,098	2,091
92	(561.8) Reliability, Planning and Standards Development Services	3,079,738	3,340,035
93	(562) Station Expenses	6,283,709	8,343,000
94	(563) Overhead Lines Expenses	8,316,030	4,406,208
95	(564) Underground Lines Expenses	12,191	
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	20,246,481	18,341,678
98	(567) Rents	2,829,825	2,890,113
99	TOTAL Operation (Enter Total of lines 83 thru 98)	55,438,802	52,409,192
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,017,028	2,329,345
102	(569) Maintenance of Structures	579,452	9,935
103	(569.1) Maintenance of Computer Hardware	1,248,578	1,322,203
104	(569.2) Maintenance of Computer Software	2,090,883	1,941,603
105	(569.3) Maintenance of Communication Equipment	103	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	143,700	165,388
107	(570) Maintenance of Station Equipment	16,048,173	14,934,723
108	(571) Maintenance of Overhead Lines	18,139,880	14,791,551
109	(572) Maintenance of Underground Lines	720,009	671,305
110	(573) Maintenance of Miscellaneous Transmission Plant	2,745	
111	TOTAL Maintenance (Total of lines 101 thru 110)	40,990,551	36,166,053
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	96,429,353	88,575,245

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	04/17/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	3,090,662	3,492,532
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,090,662	3,492,532
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)	3,090,662	3,492,532
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	17,245,704	16,777,141
135	(581) Load Dispatching	2,509,902	2,476,936
136	(582) Station Expenses	4,697,978	2,734,546
137	(583) Overhead Line Expenses	7,555,815	6,223,324
138	(584) Underground Line Expenses	4,891,302	4,842,071
139	(585) Street Lighting and Signal System Expenses	630,794	659,704
140	(586) Meter Expenses	9,682,021	9,363,084
141	(587) Customer Installations Expenses	4,883,782	5,398,576
142	(588) Miscellaneous Expenses	39,442,661	24,830,171
143	(589) Rents	647,878	268,020
144	TOTAL Operation (Enter Total of lines 134 thru 143)	92,187,837	73,573,573
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	3,002,978	1,470,831
147	(591) Maintenance of Structures	330	397
148	(592) Maintenance of Station Equipment	3,134,766	2,334,479
149	(593) Maintenance of Overhead Lines	66,998,230	49,790,819
150	(594) Maintenance of Underground Lines	11,583,499	8,557,899
151	(595) Maintenance of Line Transformers	49,968	2,550
152	(596) Maintenance of Street Lighting and Signal Systems	145,088	20,400
153	(597) Maintenance of Meters	1,401,672	1,453,825
154	(598) Maintenance of Miscellaneous Distribution Plant	1,986,660	1,528,151
155	TOTAL Maintenance (Total of lines 146 thru 154)	88,303,191	65,159,351
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	180,491,028	138,732,924
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	54	62
160	(902) Meter Reading Expenses	2,419,017	1,527,379
161	(903) Customer Records and Collection Expenses	70,177,332	47,308,005
162	(904) Uncollectible Accounts	5,153,931	6,486,856
163	(905) Miscellaneous Customer Accounts Expenses	247,392	-252,771
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	77,997,726	55,069,531

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	04/17/2020	End of 2019/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		
168	(908) Customer Assistance Expenses	130,281,148	141,594,006
169	(909) Informational and Instructional Expenses	226,960	60,414
170	(910) Miscellaneous Customer Service and Informational Expenses	3,146,869	2,995,531
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	133,654,977	144,649,951
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	31,012,001	38,528,063
182	(921) Office Supplies and Expenses	16,773,404	8,714,184
183	(Less) (922) Administrative Expenses Transferred-Credit	13,569,700	10,239,581
184	(923) Outside Services Employed	90,245,647	93,646,322
185	(924) Property Insurance	8,305,622	5,523,006
186	(925) Injuries and Damages	140,446,405	112,646,052
187	(926) Employee Pensions and Benefits	54,077,224	48,997,417
188	(927) Franchise Requirements	127,615,791	131,978,202
189	(928) Regulatory Commission Expenses	22,402,325	20,960,246
190	(929) (Less) Duplicate Charges-Cr.	2,181,084	1,622,265
191	(930.1) General Advertising Expenses	112,529	242,684
192	(930.2) Miscellaneous General Expenses	2,206,682	7,563,737
193	(931) Rents	8,564,242	11,844,364
194	TOTAL Operation (Enter Total of lines 181 thru 193)	486,011,088	468,782,431
195	Maintenance		
196	(935) Maintenance of General Plant	12,341,892	9,056,059
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	498,352,980	477,838,490
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,872,332,274	2,955,593,129

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	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arlington Valley Solar II LLC	LU	FERC Vol. 10			
2	California ISO					
3	Calipatria LLC	LU	FERC Vol. 10			
4	Calpeak Power LLC	OS				
5	Campo Verde Solar LLC	LU	FERC Vol. 10			
6	Carlsbad Energy Center LLC	LU	FERC Vol. 10			
7	Cascade Solar LLC	LU	FERC Vol. 10			
8	Catalina Solar LLC	LU	FERC Vol. 10			
9	Centinela Solar Energy LLC	LU	FERC Vol. 10			
10	Centinela Solar Energy 2 LLC	LU	FERC Vol. 10			
11	City of Escondido (Bear Valley Hydro)	LU	FERC Vol. 10			
12	City of Oceanside (San Francisco Peak)	LU	FERC Vol. 10			
13	City of Riverside	LU	FERC Vol. 10			
14	Clean Power Alliance of SoCal	LU	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.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Coram Energy LLC	LU	FERC Vol. 10			
2	CP Kelco US Inc	LU	FERC Vol. 10			
3	CSolar IV South LLC	LU	FERC Vol. 10			
4	CSolar IV West LLC	LU	FERC Vol. 10			
5	Desert Green Solar Farm LLC	LU	FERC Vol. 10			
6	Dynegy Power Marketing Inc	AD	FERC Vol. 10			
7	El Cajon Energy Center (Tolling)	LU	FERC Vol. 10			
8	Energia Sierra Juarez US LLC	LU	FERC Vol. 10			
9	Escondido Energy Center LLC	LU	FERC Vol. 10			
10	FPL Energy Green Power Wind LLC	LU	FERC Vol. 10			
11	Goal Line LP	LU	FERC Vol. 10			
12	Grossmont Hospital Corporation	LU	FERC Vol. 10			
13	HL Power Company LP	LU	FERC Vol. 10			
14	Iberdrola Renewables LLC - Mt. Wind	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	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Imperial Valley Solar I LLC (Mount Si)	LU	FERC Vol. 10			
2	Kumeyaay Wind LLC	LU	FERC Vol. 10			
3	Lakeside BioGas	LU	FERC Vol. 10			
4	Manzana Wind LLC	LU	FERC Vol. 10			
5	Maricopa West Solar PV LLC	LU	FERC Vol. 10			
6	Midway Solar	LU	FERC Vol. 10			
7	MM Prima Deshecha Energy LLC	LU	FERC Vol. 10			
8	MM San Diego LLC (Miramar RAM)	LU	FERC Vol. 10			
9	Morgan Stanley Capital Group	LU	FERC Vol. 10			
10	Naturener Glacier Wind Energy 1 LLC	EX				
11	Naturener Glacier Wind Energy 2 LLC	EX				
12	Naturener Rim Rock Wind Energy LLC	EX				
13	NLP Valley Center Solar LLC	LU	FERC Vol. 10			
14	NLP Granger A82 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	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NRG Power Marketing LLC (Tolling)	AD	FERC Vol. 10			
2	NRG Solar Borrego LLC	LU	FERC Vol. 10			
3	Oak Creek Wind Power LLC	LU	FERC Vol. 10			
4	Oasis Power Partners LLC	LU	FERC Vol. 10			
5	Ocotillo Express LLC	LU	FERC Vol. 10			
6	Olivenhain Muni Water District	LU	FERC Vol. 10			
7	Orange Grove Energy Center (Tolling)	LU	FERC Vol. 10			
8	Otay Landfill Gas I	LU	FERC Vol. 10			
9	Otay Landfill Gas II	LU	FERC Vol. 10			
10	Otay Landfill Gas V	LU	FERC Vol. 10			
11	Otay Landfill Gas VI	LU	FERC Vol. 10			
12	Otay Mesa Energy Center (Tolling)	LU	FERC Vol. 10			
13	Pacific Wind Lessee LLC	LU	FERC Vol. 10			
14	Pio Pico Energy Center	LU	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.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	San Diego County Water Authority (Hod)	LU	FERC Vol. 10			
2	San Gorgonio Westwinds II LLC	LU	FERC Vol. 10			
3	San Marcos Energy LLC	LU	FERC Vol. 10			
4	SG2 imperial Valley LLC	LU	FERC Vol. 10			
5	Sol Orchard 20 LLC (Ramona 1)	LU	FERC Vol. 10			
6	Sol Orchard 21 LLC (Ramona 2)	LU	FERC Vol. 10			
7	Sol Orchard 22 LLC (Valley Center 1)	LU	FERC Vol. 10			
8	Sol Orchard 23 LLC (Valley Center 2)	LU	FERC Vol. 10			
9	Sycamore Energy 1 LLC	LU	FERC Vol. 10			
10	Sycamore Energy 2 LLC	LU	FERC Vol. 10			
11	Tallbear Seville LLC	LU	FERC Vol. 10			
12	Yuma Co-generator Association	LU	FERC Vol. 10			
13	Anahau Energy LLC	SF	FERC Vol. 10			
14	BP Energy Company	SF	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	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Citigroup Energy Inc	SF	FERC Vol. 10			
2	City of Anaheim	SF	FERC Vol. 10			
3	City of Burbank	SF	FERC Vol. 10			
4	City of Riverside	SF	FERC Vol. 10			
5	City of San Jose	SF	FERC Vol. 10			
6	EDF Trading North America LLC	SF	FERC Vol. 10			
7	JP Morgan Ventures Energy	SF	FERC Vol. 10			
8	Macquarie Energy LLC	SF	FERC Vol. 10			
9	Marin Clean Energy	SF	FERC Vol. 10			
10	NRG Power Marketing LLC	SF	FERC Vol. 10			
11	NV Energy (Nevada Power Company)	SF	FERC Vol. 10			
12	Powerex Corporation					
13	SAAVI Energy Solutions	SF	FERC Vol. 10			
14	Sempra Gas & Power Marketing LLC	SF	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	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Shell Energy North America (US) LP	SF	FERC Vol. 10			
2	Southern California Edison Company	SF	FERC Vol. 10			
3	Procurement software					
4	Broker Fees	OS				
5	Hedging Activity	OS				
6	ONDA Energy	OS				
7	GHG Allowances	OS				
8	Other adjustments	OS				
9	Settlement Credits	OS				
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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
366,212			2,955	41,941,293	1,681,972	43,626,220	1
15,072,905				645,110,651	-22,235,999	622,874,652	2
47,070			-21,600	3,249,505	288,672	3,516,577	3
			2,535,016			2,535,016	4
347,304				40,567,294	1,410,709	41,978,003	5
422,995			100,049,892	29,803,643		129,853,535	6
53,108				4,320,590	-5,138	4,315,452	7
248,836				33,211,472	-23,782	33,187,690	8
373,705				49,996,127	2,144,068	52,140,195	9
133,149				17,299,391	664,469	17,963,860	10
3,472			35,779	140,205		175,984	11
72			636	2,759		3,395	12
							13
			-24,500			-24,500	14
22,486,042	1,125,511	1,125,511	308,133,671	1,403,097,443	20,763,753	1,731,994,867	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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)	
25,544				2,605,544	-2,434	2,603,110	1
16,108			70,004	608,163		678,167	2
299,441				39,815,374	2,105,208	41,920,582	3
410,087				44,353,806	1,284,338	45,638,144	4
12,231				1,706,193	-1,163	1,705,030	5
					-7	-7	6
8,835			7,647,960	526,174		8,174,134	7
476,123			3,672	46,144,468	368,129	46,516,269	8
17,393			7,574,243	1,434,067		9,008,310	9
				6,834		6,834	10
8,495			11,415,708	132,786		11,548,494	11
2,618			10,288	110,088		120,376	12
182,598			444,960	18,761,647		19,206,607	13
				21,276		21,276	14
22,486,042	1,125,511	1,125,511	308,133,671	1,403,097,443	20,763,753	1,731,994,867	

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)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
510,401				58,554,122	1,860,113	60,414,235	1
162,805			204,575	8,117,486	255,800	8,577,861	2
					-60,000	-60,000	3
260,203				16,433,370	5,500	16,438,870	4
45,108				3,113,438	-4,408	3,109,030	5
47,486				2,124,489	202,775	2,327,264	6
41,204				1,141,368		1,141,368	7
28,898				2,465,620		2,465,620	8
484,991				31,664,710		31,664,710	9
	257,736	257,736		5,412,447		5,412,447	10
	267,124	267,124		8,013,734		8,013,734	11
	600,651	600,651		26,422,657		26,422,657	12
5,623				655,353	-526	654,827	13
6,972				782,004	-698	781,306	14
22,486,042	1,125,511	1,125,511	308,133,671	1,403,097,443	20,763,753	1,731,994,867	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
70,032				9,878,127	262,585	10,140,712	2
5,302				358,234	-448	357,786	3
145,467				7,621,154		7,621,154	4
600,632				63,621,551	285,323	63,906,874	5
812				101,370		101,370	6
19,385			17,186,733	933,210		18,119,943	7
2,528				242,769		242,769	8
5,912				615,651		615,651	9
10,493				1,161,430		1,161,430	10
9,453				1,055,429	7,955,000	9,010,429	11
381,472			63,772,375	23,154,589		86,926,964	12
303,673				35,063,498	-28,721	35,034,777	13
108,106			66,460,034	6,996,506		73,456,540	14
22,486,042	1,125,511	1,125,511	308,133,671	1,403,097,443	20,763,753	1,731,994,867	

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.
-20,462			2,466,067	380,676		2,846,743	1
34,273				2,385,911	-3,356	2,382,555	2
12,830			2,115	1,504,094		1,506,209	3
357,250			-172,800	33,061,097	3,393,193	36,281,490	4
4,467				595,211	-428	594,783	5
9,329				1,256,671	-897	1,255,774	6
5,586				747,650	-533	747,117	7
10,320				1,387,347	-982	1,386,365	8
4,750			2,921	546,265		549,186	9
18,601			318	1,636,707		1,637,025	10
59,792				5,120,374	318,137	5,438,511	11
59,623			10,104,283	2,459,374		12,563,657	12
							13
144,424				14,442,400		14,442,400	14
22,486,042	1,125,511	1,125,511	308,133,671	1,403,097,443	20,763,753	1,731,994,867	

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	04/17/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
							4
			-630,000			-630,000	5
			241,694			241,694	6
							7
							8
							9
							10
							11
							12
			12,354,355			12,354,355	13
			6,533,988			6,533,988	14
22,486,042	1,125,511	1,125,511	308,133,671	1,403,097,443	20,763,753	1,731,994,867	

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	04/17/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
			-138,000			-138,000	2
					61,270	61,270	3
					201,188	201,188	4
					-1,736,444	-1,736,444	5
					31,785	31,785	6
					20,139,148	20,139,148	7
					-906	-906	8
					-48,759	-48,759	9
							10
							11
							12
							13
							14
22,486,042	1,125,511	1,125,511	308,133,671	1,403,097,443	20,763,753	1,731,994,867	

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: l
Curtailment of 17,477 MWh and payment/penalties of $1,887,640. Forecasting fees.
Schedule Page: 326 Line No.: 2 Column: l
CAISO allocated revenues and charges.
Schedule Page: 326 Line No.: 3 Column: l
Curtailment of 5,044 MWh and payment/penalties of $292,231. Forecasting fees.
Schedule Page: 326 Line No.: 5 Column: l
Curtailment of 12,335 MWh and payment/penalties of $1,442,309. Forecasting fees.
Schedule Page: 326 Line No.: 7 Column: l
Forecasting fees.
Schedule Page: 326 Line No.: 8 Column: l
Forecasting fees.
Schedule Page: 326 Line No.: 9 Column: l
Curtailment of 17,418 MWh and payment/penalties of $2,193,486. Forecasting fees.
Schedule Page: 326 Line No.: 10 Column: l
Curtailment of 5,750 MWh and payment/penalties of $680,908. Forecasting fees.
Schedule Page: 326.1 Line No.: 1 Column: l
Forecasting fees.
Schedule Page: 326.1 Line No.: 3 Column: l
Curtailment of 18,721 MWh and payment/penalties of $2,150,289. Forecasting fees.
Schedule Page: 326.1 Line No.: 4 Column: l
Curtailment of 14,865 MWh and payment/penalties of $1,322,935. Forecasting fees.
Schedule Page: 326.1 Line No.: 5 Column: l
Forecasting fees.
Schedule Page: 326.1 Line No.: 6 Column: l
EPA SO2 proceeds
Schedule Page: 326.1 Line No.: 8 Column: l
Curtailment of 4,472 MWh and payment/penalties of $412,133. Forecasting fees.
Schedule Page: 326.2 Line No.: 1 Column: l
Curtailment of 20,561 MWh and payments/penalties of $1,891,008. Forecasting fees.
Schedule Page: 326.2 Line No.: 2 Column: l
Curtailment of 5,921 MWh and payment/penalties of $273,418. Forecasting fees.
Schedule Page: 326.2 Line No.: 3 Column: l
Collateral Deposit
Schedule Page: 326.2 Line No.: 4 Column: l
Curtailment of 58 MWh and payment/penalties of $5,500.
Schedule Page: 326.2 Line No.: 5 Column: l
Forecasting fees.
Schedule Page: 326.2 Line No.: 6 Column: l
Curtailment of 6,886 MWh and payment/penalties of $219,576. Forecasting fees.
Schedule Page: 326.2 Line No.: 13 Column: l
Forecasting fees.
Schedule Page: 326.2 Line No.: 14 Column: l
Forecasting fees.
Schedule Page: 326.3 Line No.: 2 Column: l
Curtailment of 2,516 MWh and payment/penalties of $259,326. Forecasting fees.
Schedule Page: 326.3 Line No.: 3 Column: l
Forecasting fees.
Schedule Page: 326.3 Line No.: 5 Column: l
Curtailment of 3,073 MWh and payments/penalties of $358,315. Forecasting fees.
Schedule Page: 326.3 Line No.: 11 Column: l
Contract termination payment.
Schedule Page: 326.3 Line No.: 13 Column: l
Forecasting fees.

Schedule Page: 326.4 Line No.: 2 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 4 Column: l

Curtailment of 23,051 MWh and payments/penalties of $3,854,211.

Schedule Page: 326.4 Line No.: 5 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 6 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 7 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 8 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 11 Column: l

Curtailment of 7,093 MWh and payments/penalties of $536,534. Forecasting fees.

Schedule Page: 326.6 Line No.: 3 Column: l

Software & support

Schedule Page: 326.6 Line No.: 4 Column: l

Contract administration expenses.

Schedule Page: 326.6 Line No.: 5 Column: l

Contract hedging activity.

Schedule Page: 326.6 Line No.: 6 Column: l

Engineering services.

Schedule Page: 326.6 Line No.: 7 Column: l

Amortization of GHG Allowances.

Schedule Page: 326.6 Line No.: 8 Column: l

Other adjustments

Schedule Page: 326.6 Line No.: 9 Column: l

Settlement amounts received from PG&E and Edison.

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	04/17/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	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			

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**	

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.
	302,746,348		302,746,348	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	**302,746,348**	**0**	**302,746,348**	

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	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	04/17/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,144,335
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	-1,674,472
6	Abandoned Projects	2,060,358
7	Cost of Financing	450,071
8	Insurance	226,390
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	2,206,682

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			17,665,449		17,665,449
2	Steam Production Plant	23,437,389				23,437,389
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	25,204,224				25,204,224
7	Transmission Plant	168,094,874			1,947,961	170,042,835
8	Distribution Plant	269,034,343			1,971,556	271,005,899
9	Regional Transmission and Market Operation					
10	General Plant	22,969,518				22,969,518
11	Common Plant-Electric	38,502,870		54,035,702		92,538,572
12	TOTAL	547,243,218		71,701,151	3,919,517	622,863,886

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	04/17/2020	End of 2019/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	29,040		-10.58	6.50		7.33
14	311-Palomar	60,307		-2.30	3.75		
15	312-Desert Star	54,373		-4.27	6.67		7.33
16	312-Palomar	107,510		-2.30	3.36		
17	314-Desert Star	14,625		-10.49	8.23		7.33
18	314-Palomar	116,376		-1.41	3.59		
19	315-Desert Star	48,255		-0.08	6.34		7.33
20	315-Palomar	37,254		-0.32	3.42		
21	316-Desert Star	4,953		-0.70	7.54		7.33
22	316-Palomar	48,422		-0.25	4.18		
23	SUBTOTAL	521,115					
24							
25	OTHER PRODUCTION						
26	341-CPEP	1,882		-17.45	9.41		
27	341-Desert Star	1,847		-30.74	10.84		7.33
28	341-Miramar	5,076		-6.76	4.84		
29	341-Palomar	14,821		-3.29	3.80		
30	342-CPEP	627		-5.02	7.65		
31	342-Desert Star	795		-24.16	8.49		7.33
32	342-Miramar	5,233		-2.92	4.52		
33	342-Palomar	14,914		-1.45	3.69		
34	343-CPEP	16,862					
35	343-Desert Star	24,351			6.03		7.33
36	343-Miramar	54,120					
37	343-Palomar						
38	344-CPEP	1,990		-9.07	8.20		
39	344-Desert Star	108,119		-0.42	5.24		7.33
40	344-Miramar	19,736		-2.61	4.98		
41	344-Palomar	171,841		-0.60	3.39		
42	344-Solar	59,318					
43	344-Wind	257					
44	345-CPEP	834		-14.47	8.55		
45	345-Desert Star	9,194		4.71	5.64		7.33
46	345-Miramar	13,461		-1.08	4.25		
47	345-Palomar	6,706		3.06	3.51		
48	345-Solar	2,316					
49	345-Wind						
50	(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) 04/17/2020	Year/Period of Report End of 2019/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-CPEP	3,551					
13	346-Desert Star	22,342			5.11		
14	346-Miramar	4,312					
15	346-Palomar	593					
16	SUBTOTAL	565,098					
17							
18	TRANSMISSION-SWPL						
19	352	24,068					
20	353	286,416					
21	354	62,015					
22	355	10,309					
23	356	46,249					
24	359	5,324					
25	SUBTOTAL	434,381					
26							
27	TRANSMISSION-SRPL						
28	352	120,967					
29	353	161,201					
30	354	766,452					
31	355	3,344					
32	356	173,392					
33	357	80,502					
34	358	126,452					
35	359	227,676					
36	SUBTOTAL	1,659,986					
37							
38	TRANSMISSION-OTHER						
39	352	473,284					
40	353	1,396,793					
41	353.4	1,420					
42	354	76,087					
43	355	650,401					
44	356	466,236					
45	357	384,995					
46	358	391,643					
47	359	91,720					
48	SUBTOTAL	3,932,579					
49							
50	(continued)						

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	DISTRIBUTION						
13	361	10,265					
14	362.1	585,408					
15	363	127,142					
16	364	813,033					
17	365	801,789					
18	366	1,366,105					
19	367	1,675,052					
20	368.1	667,382					
21	368.2	34,503					
22	369.1	189,724					
23	369.2	372,190					
24	370.1	5,985					
25	370.11	194,006					
26	E370.20	7,267					
27	E370.21	55,002					
28	E371.00	9,587					
29	E373.20	32,380					
30	SUBTOTAL	6,946,820					
31							
32	GENERAL						
33	390	45,575					
34	392.2	58					
35	393.1	47					
36	394.11	34,609					
37	394.2	278					
38	395.1	5,334					
39	397.1	302,362					
40	397.2	7,907					
41	397.6	14,039					
42	397.7	579					
43	398.1	8,517					
44	398.2	38,413	10.00		10.42	SQ	9.37
45	SUBTOTAL	457,718					
46							
47	TOTAL	14,517,697					
48							
49	See Footnote						
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	04/17/2020	2019/Q4

FOOTNOTE DATA

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

Reclassification of 2019 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	-	17,665,449	-	17,665,449
Steam Production	23,934,637	-	-	23,934,637
Nuclear Production	-	-	-	-
Other Production	23,488,423	-	-	23,934,637
Transmission Plant	166,215,634	-	1,937,258	168,152,892
Distribution Plant	272,132,136	-	1,982,260	274,114,396
General Plant	22,969,518	-	-	22,969,518
Common Plant-Electric	38,502,870	54,035,702	-	92,538,572
Total Ratemaking Electric Depreciation & Amort.	547,243,218	71,701,151	3,919,517	622,863,886

Schedule Page: 336.2 Line No.: 49 Column: a

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

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	04/17/2020	End of 2019/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.19-01-013 NET ENERGY METERING		5,673	5,673	
2					
3	D.19-01-014 ENERGY EFFICIENCY		11,372	11,372	
4			1,582	1,582	
5					
6	D.19-01-016 CALIFORNIA RENEWABLES		11,071	11,071	
7					
8	D.19-01-040 NUCLEAR GENERATION		153,136	153,136	
9					
10	D.19-01-041 WATER-ENERGY NEXUS PROGRAMS		5,027	5,027	
11			591	591	
12					
13	D.19-01-043 NET ENERGY METERING		3,168	3,168	
14					
15	D.19-01-44 MARINE MITIGATION		11,524	11,524	
16					
17	D.19-02-017 RESIDENTIAL RATE STRUCTURES		16,351	16,351	
18					
19	D.19-02-020 ENERGY SAVINGS ASSISTANCE		7,056	7,056	
20			982	982	
21					
22	D.19-03-005 NET ENERGY METERING		15,933	15,933	
23					
24	D.19-03-021 DISTRIBUTION RESOURCES PLANS		6,862	6,862	
25					
26	D.19-03-022 TRANSPORTATION ELECTRICFICATION		18,652	18,652	
27					
28	D.19-04-031 PIPELINE SAFETY AND RELIABILITY		22,987	22,987	
29					
30	D.19-04-032 DAIRY BIOMETHANE PILOT PROJECTS		1,412	1,412	
31					
32	D.19-04-033 PIPELINE SAFETY AND RELIABILITY		22,118	22,118	
33					
34	D.19-04-034 DEMAND RESPONSE		141,072	141,072	
35					
36	D.19-04-037 NET ENERGY METERING		8,973	8,973	
37					
38	D.19-04-038 PIPELINE SAFETY AND RELIABILITY		27,495	27,495	
39					
40	D. 19-05-035 WILDFIRE EXPENSE		6,783	6,783	
41					
42	D. 19-08-008 STATEWIDE OUTREACH PROGRAM		1,308	1,308	
43			181	181	
44					
45	D. 19-08-033 NUCLEAR GENERATION		13,127	13,127	
46	TOTAL	11,255,425	16,728,399	27,983,824	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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. 19-09-012 BIOMETHANE PILOT		416	416	
3					
4	D. 19-09-015 CALIFORNIA RENEWABLES		2,224	2,224	
5					
6	D. 19-09-019 NUCLEAR GENERATION		50,473	50,473	
7					
8	D. 19-09-020 CUSTOMER INFO SYSTEM		67,373	67,373	
9			9,375	9,375	
10					
11	D. 19-09-024 CUSTOMER INFO SYSTEM		63,025	63,025	
12			8,770	8,770	
13					
14	D. 19-09-049 NUCLEAR GENERATION		112,099	112,099	
15					
16	D. 19-09-050 SAFETY MODEL ASSESSMENT		120,042	120,042	
17			16,703	16,703	
18					
19	D. 19-10-015 ALTERNATIVE FUEL VEHICLE		9,568	9,568	
20					
21	D. 19-10-016 ENERGY EFFICIENCY		25,839	25,839	
22			3,595	3,595	
23					
24	D. 19-10-017 AFFILIATE TRANSACTIONS		45,160	45,160	
25					
26	D. 19-10-020 POWER CHARGE INDIFFERENCE		18,563	18,563	
27					
28	D. 19-10-046 NET ENERGY METERING		7,238	7,238	
29					
30	D. 19-10-047 POWER LINES		17,910	17,910	
31					
32	D. 19-10-048 NET ENERGY METERING		1,611	1,611	
33					
34	D. 19-10-049 POWER CHARGE INDIFFERENCE		18,495	18,495	
35					
36	D. 19-10-050 ELECTRIC PROGRAM INVESTMENT		1,638	1,638	
37					
38	D. 19-10-051 ENERGY EFFICIENCY		1,374	1,374	
39			159	159	
40					
41	D. 19-10-052 RESIDENTIAL RATE STRUCTURES		6,808	6,808	
42					
43	D. 19-10-053 POWER CHARGE INDIFFERENCE		6,707	6,707	
44					
45	D. 19-11-012 ELECTRIC PROGRAM INVESTMENT		4,608	4,608	
46	TOTAL	11,255,425	16,728,399	27,983,824	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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. 19-11-013 2015 NUCLEAR DECOMISSIONING		75,780	75,780	
3					
4	D. 19-11-014 AFFILIATE TRANSACTIONS		55,686	55,686	
5					
6	D. 19-12-015 STATEWIDE OUTREACH PROGRAM		3,560	3,560	
7			412	412	
8					
9	D. 19-12-017 WILDFIRE EXPENSE		22,460	22,460	
10					
11	D. 19-12-018 PIPELINE SAFETY AND RELIABILITY		9,785	9,785	
12					
13	D. 19-12-019 ELECTRICITY INTEGRATED RESOURCE		20,496	20,496	
14					
15	D. 19-12-020 2015 NUCLEAR DECOMISSIONING		11,640	11,640	
16					
17	California Public Utilities Commission fees	9,790,548		9,790,548	
18		1,464,877		1,464,877	
19					
20	FERC Proceedings		118,823	118,823	
21			45,706	45,706	
22					
23	Miscellaneous		11,285,490	11,285,490	
24			3,944,352	3,944,352	
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	11,255,425	16,728,399	27,983,824	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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	5,673					1
							2
Elec	928	11,372					3
Gas	928	1,582					4
							5
Elec	928	11,071					6
							7
Elec	928	153,136					8
							9
Elec	928	5,027					10
Gas	928	591					11
							12
Elec	928	3,168					13
							14
Elec	928	11,524					15
							16
Elec	928	16,351					17
							18
Elec	928	7,056					19
Gas	928	982					20
							21
Elec	928	15,933					22
							23
Elec	928	6,862					24
							25
Elec	928	18,652					26
							27
Gas	928	22,987					28
							29
Gas	928	1,412					30
							31
Gas	928	22,118					32
							33
Elec	928	141,072					34
							35
Elec	928	8,973					36
							37
Gas	928	27,495					38
							39
Elec	928	6,783					40
							41
Elec	928	1,308					42
Gas	928	181					43
							44
Elec	928	13,127					45
		27,983,824					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	04/17/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Gas	928	416					2
							3
Elec	928	2,224					4
							5
Elec	928	50,473					6
							7
Elec	928	67,373					8
Gas	928	9,375					9
							10
Elec	928	63,025					11
Gas	928	8,770					12
							13
Elec	928	112,099					14
							15
Elec	928	120,042					16
Gas	928	16,703					17
							18
Elec	928	9,568					19
							20
Elec	928	25,839					21
Gas	928	3,595					22
							23
Elec	928	45,160					24
							25
Elec	928	18,563					26
							27
Elec	928	7,238					28
							29
Elec	928	17,910					30
							31
Elec	928	1,611					32
							33
Elec	928	18,495					34
							35
Elec	928	1,638					36
							37
Elec	928	1,374					38
Gas	928	159					39
							40
Elec	928	6,808					41
							42
Elec	928	6,707					43
							44
Elec	928	4,608					45
		27,983,824					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	04/17/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Elec	928	75,780					2
							3
Elec	928	55,686					4
							5
Elec	928	3,560					6
Gas	928	412					7
							8
Elec	928	22,460					9
							10
Gas	928	9,785					11
							12
Elec	928	20,496					13
							14
Elec	928	11,640					15
							16
Elec	928	9,790,548					17
Gas	928	1,464,877					18
							19
Elec	928	118,823					20
Gas	928	45,706					21
							22
Elec	928	11,285,490					23
Gas	928	3,944,352					24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		27,983,824					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	04/17/2020	End of 2019/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 Electrical Power	NONE
21	Research Institute	NONE
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	
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	04/17/2020	End of 2019/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)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
831,129		588	831,129		9
23,996		408	23,996		10
					11
					12
					13
					14
855,125			855,125		15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
	7,795,923	588	7,795,923		27
					28
	7,795,923		7,795,923		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	04/17/2020	End of 2019/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	10,239,896		
4	Transmission	12,316,097		
5	Regional Market			
6	Distribution	38,255,186		
7	Customer Accounts	18,054,752		
8	Customer Service and Informational	17,968,806		
9	Sales			
10	Administrative and General	38,886,055		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	135,720,792		
12	Maintenance			
13	Production	1,900,423		
14	Transmission	11,993,997		
15	Regional Market			
16	Distribution	16,201,917		
17	Administrative and General	1,959,391		
18	TOTAL Maintenance (Total of lines 13 thru 17)	32,055,728		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,140,319		
21	Transmission (Enter Total of lines 4 and 14)	24,310,094		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	54,457,103		
24	Customer Accounts (Transcribe from line 7)	18,054,752		
25	Customer Service and Informational (Transcribe from line 8)	17,968,806		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	40,845,446		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	167,776,520	43,472,253	211,248,773
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	163,451		
35	Transmission	2,636,878		
36	Distribution	24,637,569		
37	Customer Accounts	8,959,890		
38	Customer Service and Informational	2,215,868		
39	Sales			
40	Administrative and General	14,783,019		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	53,396,675		
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	798,079		

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	7,019,177		
49	Administrative and General	556,094		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	8,373,350		
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	163,451		
56	Transmission (Lines 35 and 47)	3,434,957		
57	Distribution (Lines 36 and 48)	31,656,746		
58	Customer Accounts (Line 37)	8,959,890		
59	Customer Service and Informational (Line 38)	2,215,868		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	15,339,113		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	61,770,025	13,959,290	75,729,315
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	229,546,545	57,431,543	286,978,088
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	73,003,599	122,790,694	195,794,293
69	Gas Plant	16,882,004	22,543,854	39,425,858
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	89,885,603	145,334,548	235,220,151
72	Plant Removal (By Utility Departments)			
73	Electric Plant	8,049,170	10,914,674	18,963,844
74	Gas Plant	829,930	1,663,092	2,493,022
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,879,100	12,577,766	21,456,866
77	Other Accounts (Specify, provide details in footnote):			
78	3rd Party Billings, Gas	-1,552	1,780,662	1,779,110
79	3rd Party Billings, Electric	477,274	5,100,798	5,578,072
80	Affiliate Billings, Gas		8,241,932	8,241,932
81	Affiliate Billings, Electric		21,426,649	21,426,649
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	475,722	36,550,041	37,025,763
96	TOTAL SALARIES AND WAGES	328,786,970	251,893,898	580,680,868

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

FERC accounts 417 and 426 are not included in the detail classification lines or summary totals.
FERC 417 for 2019 amounts to $5,026,739
FERC 426 for 2019 amounts to $1,068,664

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	04/17/2020	End of 2019/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	Balance Beg. of Year	Additions	Retire From Serv.	Adjs.	Transfers	Balance End of Year
303 Misc. Intangible Plant	587,596,754	50,902,525	16,121,588	(3,145,591)	(1,352,415)	617,879,685
389 Land & Land Rights	8,351,371			(828,802)		7,522,569
390 Structures & Improvs.	429,009,072	25,263,414	12,544,407			441,728,079
391 Office Furn. & Equip.	96,433,541	25,050,669	11,182,706		25,853	110,327,357
392 Transportation Equip.	12,364,022	177,226			(25,853)	12,515,395
393 Stores Equipment	333,836					333,836
394 Tools, Shop & Garage Eq.	3,517,731	35				3,517,766
395 Laboratory Equipment	1,731,117					1,731,117
396 Power Equipment	0					0
397 Communication Eq.	237,752,906	19,061,405	2,006,282	654,518	2,116	255,464,663
398 Misc. Equipment	5,157,597		21,183			5,136,414
SPL Topside	5,725,081			(5,725,081)		0
FIN 47 ARC-Common	2,652,762					2,652,762
Fleet Capital Leases	24,691,125	54,003,016	3,302,091	(11,788,918)		63,603,132
Other Capital Leases	0	117,108,736				117,108,736
TOTAL COMMON PLANT	1,403,527,997	291,567,026	45,178,257	(20,833,874)	(1,350,299)	1,639,521,511
Construction Work in Prog.	168,580,320	89,226,462				257,806,782
TOTAL COMMON PLANT	1,572,108,317	380,793,488	45,178,257	(20,833,874)	(1,350,299)	1,897,328,293

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	04/17/2020	End of 2019/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, 2019 Accumulated Depreciation
303	Misc. Intangible Plant	417,997,084
389	Land & Land Rights	27,776
390	Structures and Improvements	162,271,058
391	Office Furniture & Equipment	38,804,383
392	Transportation Equipment	2,592,450
393	Stores Eqiupment	38,854
394	Tools, Shop, & Garage Equipment	1,099,002
395	Laboratory Equipment	864,731
396	Power Operated Equipment	(192,979)
397	Communication Equipment	94,906,327
398	Miscellaneous Equipment	651,422
108.4	Retirement Work in Progress	0
	FIN 47 Accummulated Depreciation	3,377,488
	Fleet Capital Lease	22,306,943
	Other Capital Lease	14,269,573
	Total Accumulated Depreciation	759,014,112

Split of Common Utility Plant
to Departments: (excluding CWIP) December 31,2019

		Balance End of Year	Accumulated Depreciation
Electric	72.22%	1,184,062,435	548,159,991
Gas	27.78%	455,459,076	210,854,121
TOTAL	100.00%	1,639,521,511	759,014,112

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	04/17/2020	End of 2019/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		74,820,965
389 Land and Land Rights		1
390 Structures & Improvements		15,291,948
391 Office Furniture & Equipment		17,957,786
392 Transportation Equipment		1,154,147
393 Stores Equipment		17,593
394 Portable Tools		188,381
395 Laboratory Equipment		76,862
396 Power Operated Equipment		0
397 Communication Equipment		18,261,590
398 Miscellaneous Equipment		364,999
TOTAL		128,134,272

(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 2018-2019 and 2019-2020. 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 2019.
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	04/17/2020	End of 2019/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)	201,707,787	296,202,799	475,234,195	645,153,593
3	Net Sales (Account 447)	(105,379,360)	(165,247,779)	(275,870,498)	(340,127,281)
4	Transmission Rights				
5	Ancillary Services	(1,428,419)	(2,050,664)	(1,790,806)	(1,421,757)
6	Other Items (list separately)				
7	Congestion	1,232,098	2,316,018	3,181,925	6,484,812
8	CRR (Congestion Revenue Rights)	(371,956)	(6,254,646)	(13,283,220)	(23,856,374)
9	GMC (Grid Management Charges)	2,311,366	4,617,508	7,418,450	9,626,344
10	Other	(3,186,294)	(5,335,334)	(3,058,617)	(4,277,768)
11	UFE (Unaccounted for Energy)	680,990	4,304,649	2,119,054	1,267,239
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	95,566,212	128,552,551	193,950,483	292,848,808

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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	1,374,780	MWH	10,292,869	2,200,266	MWH	11,714,627
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)	1,374,780		10,292,869	2,200,266		11,714,627

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	3,060	14	17	3,060					
2	February	3,350	22	18	3,350					
3	March	2,851	11	17	2,851					
4	Total for Quarter 1				9,261					
5	April	2,815	8	18	2,815					
6	May	2,624	14	19	2,624					
7	June	2,956	10	17	2,956					
8	Total for Quarter 2				8,395					
9	July	3,698	24	14	3,698					
10	August	3,686	26	16	3,686					
11	September	4,175	4	14	4,175					
12	Total for Quarter 3				11,559					
13	October	3,430	24	16	3,430					
14	November	2,929	18	17	2,929					
15	December	2,999	18	18	2,999					
16	Total for Quarter 4				9,358					
17	Total Year to Date/Year				38,573					

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	04/17/2020	End of 2019/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	04/17/2020	End of 2019/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)	14,405,807
3	Steam	2,498,380			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage	46,688	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	9,822,599
7	Other	80,223			
8	Less Energy for Pumping	67,150	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	2,558,141	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	34,122
10	Purchases	22,486,042	27	Total Energy Losses	781,655
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	25,044,183
12	Received	1,125,511			
13	Delivered	1,125,511			
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)	25,044,183			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,261,576	450,211	3,060	14	17
30	February	1,202,647	1,056,088	3,350	22	18
31	March	1,121,285	734,048	2,851	11	17
32	April	1,050,614	620,369	2,815	8	18
33	May	1,103,865	822,589	2,624	14	19
34	June	1,092,194	869,391	2,956	10	17
35	July	1,177,035	987,500	3,698	24	14
36	August	1,318,955	1,265,487	3,686	26	16
37	September	1,476,578	1,071,464	4,175	4	14
38	October	1,231,845	962,016	3,430	24	16
39	November	1,191,336	415,691	2,929	18	17
40	December	1,177,877	567,745	2,999	18	18
41	TOTAL	14,405,807	9,822,599			

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	04/17/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *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	3566	1236
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	32	3
12	Net Generation, Exclusive of Plant Use - KWh	1181828807	73140857
13	Cost of Plant: Land and Land Rights	14480000	0
14	Structures and Improvements	78692586	5075863
15	Equipment Costs	517139279	99313210
16	Asset Retirement Costs	0	0
17	Total Cost	610311865	104389073
18	Cost per KW of Installed Capacity (line 17/5) Including	1078.2895	1087.3862
19	Production Expenses: Oper, Supv, & Engr	1588000	38262
20	Fuel	50415246	4056482
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	4096832	42447
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2593691	220617
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	494	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	67041	0
31	Maintenance of Boiler (or reactor) Plant	541134	0
32	Maintenance of Electric Plant	3977897	1129173
33	Maintenance of Misc Steam (or Nuclear) Plant	7852527	50384
34	Total Production Expenses	71132862	5537365
35	Expenses per Net KWh	0.0602	0.0757

Line No.	Item (a)	Palomar (b)			Miramar (c)		
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	8396823	0	0	722436	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	6.004	0.000	0.000	5.615	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.875	0.000	0.000	5.494	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.043	0.000	0.000	0.055	0.000	0.000
44	Average BTU per KWh Net Generation	7357.000	0.000	0.000	10144.000	0.000	0.000

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	04/17/2020	End of 2019/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
8760	197	0	7
450	47	0	8
450	47	0	9
450	47	0	10
23	1	0	11
1316551657	7036054	0	12
0	0	0	13
31339528	1882477	0	14
302510836	24932455	0	15
109537	0	0	16
333959901	26814932	0	17
623.0595	570.5305	0	18
933196	11887	0	19
42897134	573031	0	20
0	0	0	21
1931281	23575	0	22
0	0	0	23
0	0	0	24
1002220	112017	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	15969	0	30
2634600	0	0	31
7432008	682699	0	32
1261700	28940	0	33
58092139	1448118	0	34
0.0441	0.2058	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
GAS			GAS						36
MCF			MCF						37
9824686	0	0	79561	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
4.366	0.000	0.000	7.202	0.000	0.000	0.000	0.000	0.000	41
4.272	0.000	0.000	7.047	0.000	0.000	0.000	0.000	0.000	42
0.033	0.000	0.000	0.081	0.000	0.000	0.000	0.000	0.000	43
7690.000	0.000	0.000	11613.000	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	04/17/2020	End of 2019/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

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	04/17/2020	End of 2019/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)	

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	04/17/2020	End of 2019/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
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

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	04/17/2020	End of 2019/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			3,002,210
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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	45,020					1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

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	04/17/2020	End of 2019/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	Miguel	East County	500.00	500.00	1S,3	53.59		1
2	Imperial Valley	North Gila	500.00	500.00	1S,3	79.45		1
3	North Gila	Palo Verde	500.00	500.00	3	114.45		1
4	Suncrest	Ocotillo Switchyard	500.00	500.00	3	67.48		1
5	East County	Imperial Valley	500.00	500.00	1S,3	30.74		1
6	Octillo Switchyard	Imperial Valley	500.00	500.00	3	21.60		1
7	Octillo Switchyard	Ocotillo Express Sub	500.00	500.00	3	0.06		1
8	Total 500kV Pole Line Mi					367.37		7
9	San Luis Rey		230.00	230.00	3,1S		30.48	2
10			230.00	230.00	2W	4.26		1
11		Mission	230.00	230.00	4		0.05	2
12	San Onofre		230.00	230.00	2S		0.43	5
13			230.00	230.00	2S,3		16.76	2
14		San Luis Rey	230.00	230.00	1S,2W	0.75		1
15	San Luis Rey		230.00	230.00	1S,3		5.81	2
16		Encina	230.00	230.00	1S,3		1.49	2
17	San Luis Rey		230.00	230.00	2W	4.26		1
18			230.00	230.00	1S,3		30.48	2
19		Mission	230.00	230.00	4		0.05	2
20	San Luis Rey		230.00	230.00	1S,2W,3S,3	17.61		1
21			230.00	230.00	1S		0.07	2
22		San Onofre	230.00	230.00	2S		0.45	5
23	San Onofre		230.00	230.00	1S,3		6.30	2
24			230.00	230.00	2S,3		0.50	5
25		Talega	230.00	230.00	3	0.11		1
26	San Onofre		230.00	230.00	2W,2S	0.75		1
27			230.00	230.00	2S		0.43	5
28		San Luis Rey	230.00	230.00	2S,3		16.76	2
29	San Luis Rey		230.00	230.00	1S,3		5.84	2
30			230.00	230.00	1S,3		1.56	2
31			230.00	230.00	3		7.19	2
32			230.00	230.00	1S		5.16	2
33			230.00	230.00	1S		0.82	2
34		Palomar Energy	230.00	230.00	1S	0.26		1
35	Encina		230.00	230.00	1S,3		17.91	2
36					TOTAL	1,445.94	668.24	511

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	04/17/2020	End of 2019/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		Penasquitos	230.00	230.00	1S		0.12	2
2	Penasquitos		230.00	230.00	1S		2.20	2
3		Old Town	230.00	230.00	1S	7.19		1
4	Palomar		230.00	230.00	1S		0.18	2
5		Old Town	230.00	230.00	1S		0.22	2
6	Palomar		230.00	230.00	1S		0.18	2
7		Old Town	230.00	230.00	1S		0.22	2
8	East County	Eco Gen 1	230.00	230.00	1S		0.23	2
9	Miguel	Bay Blvd	230.00	230.00	2S		9.65	2
10	Miguel		230.00	230.00	1S,3		23.29	2
11			230.00	230.00	3		0.67	2
12		Sycamore Canyon	230.00	230.00	1S,3		3.91	2
13	Miguel		230.00	230.00	1S,3		9.08	2
14			230.00	230.00	1S,3		14.84	2
15			230.00	230.00	1S		1.45	2
16			230.00	230.00	1S,3		1.19	2
17		Mission	230.00	230.00	1S		7.51	2
18	Miguel		230.00	230.00	1S		9.17	2
19			230.00	230.00	1S		0.82	2
20			230.00	230.00	1S,3		9.28	2
21		Mission	230.00	230.00	1S,3		14.82	2
22	Bay Boulavard		230.00	230.00	4	2.83		1
23			230.00	230.00	4	0.57		1
24		Silvergate	230.00	230.00	1S,3	3.86		1
25	Old Town		230.00	230.00	1S	0.10		1
26		Mission	230.00	230.00	1S		3.77	2
27	Old Town		230.00	230.00	1S	0.09		1
28			230.00	230.00	1S		3.80	2
29	Old Town		230.00	230.00	4		7.05	2
30		Silvergate	230.00	230.00	4		0.59	2
31	Old Town		230.00	230.00	4		7.05	2
32		Silvergate	230.00	230.00	4		0.59	2
33	Talega		230.00	230.00	1S,3	34.24		1
34			230.00	230.00	3		7.69	2
35		Escondido	230.00	230.00	1S,3		9.12	2
36					TOTAL	1,445.94	668.24	511

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	04/17/2020	End of 2019/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	Otay Mesa		230.00	230.00	1S	0.11		1
2		Tijuana	230.00	230.00	3	1.60		1
3	Otay Mesa	Miguel	230.00	230.00	1S,3		8.88	2
4	Miguel		230.00	230.00	1S,3		23.60	2
5			230.00	230.00	3		0.67	2
6		Sycamore	230.00	230.00	3		3.64	2
7	Otay Mesa	Miguel	230.00	230.00	1S,3		8.92	2
8	Miguel		230.00	230.00	1S		9.53	2
9		Bay Blvd	230.00	230.00	4	0.17		1
10	Imperial Valley	NOSDGE23043_1	230.00	230.00	1S	0.04		1
11	IV Bay 12N	NOSDGE23045-6_1	230.00	230.00	1S	0.06		2
12	IV Bay 13N	NOSDGE23045-6_1	230.00	230.00	1S	0.06		2
13	IV Bay 13S	NOSDGE23047-8_1	230.00	230.00	1S	0.09		2
14	IV Bay 14S	NOSDGE23047-8_1	230.00	230.00	1S	0.09		2
15	Imperial Valley	La Rosita	230.00	230.00	1S,2S,3		5.75	2
16	Palomar Energy		230.00	230.00	1S		0.81	2
17			230.00	230.00	1S,3		12.46	2
18			230.00	230.00	3	6.18		1
19			230.00	230.00	1S		4.75	2
20		Sycamore	230.00	230.00	1S	0.36		1
21	Talega		230.00	230.00	3	0.11		1
22			230.00	230.00	1S,3		6.30	2
23		San Onofre	230.00	230.00	2S		0.50	2
24	Encina		230.00	230.00	1S,3		10.09	2
25		Penasquitos	230.00	230.00	1S,3		7.90	2
26	Sycamore Canyon		230.00	230.00	1S,3		21.75	2
27		Suncrest	230.00	230.00	4		6.23	2
28	Sycamore Canyon		230.00	230.00	1S,3		21.75	2
29		Suncrest	230.00	230.00	4		6.23	2
30	Imperial Valley	NOSDGE23061_1	230.00	230.00	1S	0.06		1
31	Imperial Valley		230.00	230.00	1S		2.78	2
32			230.00	230.00	2S		0.11	2
33			230.00	230.00	3		2.34	2
34		Drew Switchyard	230.00	230.00	3S		0.10	1
35	Drew Switchyard	NOSDGE23067_1	230.00	230.00	1S	0.04		1
36					TOTAL	1,445.94	668.24	511

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Drew Switchyard	NOSDGE23068_1	230.00	230.00	1S	0.04		1
2	Pio Pico Generator	Otay Mesa	230.00	230.00	1S	0.04		1
3	Penasquitos		230.00	230.00	1S		2.83	2
4			230.00	230.00	4	10.54		1
5			230.00	230.00	4	0.93		1
6		Sycamore Canyon	230.00	230.00	4	0.39		1
7	Encina	Encina Gen 1	230.00	230.00	4	0.03		1
8	San Luis Rey		230.00	230.00	1S		0.09	2
9		GIS Terminal	230.00	230.00	4		0.10	2
10	San Luis Rey		230.00	230.00	1S		0.09	2
11		GIS Terminal	230.00	230.00	4		0.09	2
12	Imperial Valley	Phase Shifting Transformer	230.00	230.00	1S		0.17	2
13	Z172244	Z172242	230.00	230.00	1S		0.07	2
14	Z189533	Z189535	230.00	230.00	3	0.27		1
15	East County	Eco Gen 1	230.00	230.00	3		0.23	2
16	Drew Switchyard		230.00	230.00	1S		2.39	2
17		Z46503	230.00	230.00	3		2.71	2
18	Total 230kV Pole Line Mi					98.09	471.09	209
19	Encina Switchyard		138.00	230.00	1S		0.04	2
20		Cannon	138.00	230.00	1S		0.11	2
21	Encina Switchyard		138.00	230.00	1S,3		1.47	2
22			138.00	230.00	2W,1S,2S,3S,3	17.01		1
23	Z105030	Batiquitos	138.00	230.00	4	0.72		1
24			138.00	230.00	4	0.72		1
25		Penasquitos	138.00	230.00	3		3.33	2
26	Palomar		138.00	138.00	1S	0.03		1
27		Batiquitos	138.00	230.00	1S		2.68	2
28	Encina Switchyard		138.00	230.00	1S,3		1.48	2
29		Palomar	138.00	230.00	1S,2S,3		1.61	2
30	Telegraph Canyon	Proctor Valley	138.00	138.00	1W,1S,3		2.60	2
31	Friars		138.00	138.00	4	0.17		1
32			138.00	138.00	1S,3		4.11	2
33			138.00	138.00	1S,3		1.82	2
34			138.00	138.00	1S,3	5.43		1
35		Penasquitos	138.00	138.00	1S,3		1.40	2
36					TOTAL	1,445.94	668.24	511

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	04/17/2020	End of 2019/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Doublet Tap		138.00	138.00	1W,1S		0.52	3
2		Doublet	138.00	138.00	1W,1S		0.79	2
3	Shadowridge	Z119772	138.00	138.00	1S		3.74	2
4	Z119772		138.00	138.00	1W,1S,3	0.20		1
5		NC Metering	138.00	138.00	1W	0.39		1
6	Z119772		138.00	230.00	3		1.11	2
7		Chicarita	138.00	138.00	2W,2S	10.91		1
8	Telegraph Canyon		138.00	138.00	1S	0.03		1
9			138.00	138.00	3		5.80	2
10			138.00	138.00	4	4.04		1
11	Z223732		138.00	138.00	3			1
12		Z189532	138.00	138.00	3	3.79		1
13			138.00	138.00	3	0.39		1
14		Grant Hill	138.00	138.00	1W,1S	1.01		1
15	Capistrano		138.00	138.00	1W	0.10		1
16			138.00	138.00	1S,3		1.56	2
17			138.00	138.00	1S,3		4.69	2
18		Pico	138.00	138.00	4		0.32	2
19	Santee		138.00	138.00	1W,1S	2.34		1
20			138.00	138.00	1S		4.61	2
21			138.00	138.00	2S	0.27		1
22		Los Coches	138.00	138.00	2S	0.08		1
23	Sycamore		138.00	138.00	4	0.20		1
24		Chicarita	138.00	138.00	1W,2W,1S,2S	5.78		1
25	Sycamore		138.00	138.00	1S		6.65	2
26		Santee	138.00	138.00	1W,1S	1.55		1
27	Mission		138.00	138.00	1W	0.09		1
28			138.00	138.00	1S,3		3.23	2
29	Z677977	Z874970	138.00	138.00	3	4.97		2
30	Z874970	Carlton Hills	138.00	138.00	1S,3		1.48	2
31	Telegraph Canyon		138.00	138.00	1S	0.04		1
32			138.00	138.00	1S,3		2.55	2
33		Miguel 60 Tap	138.00	138.00	1S,3		0.61	2
34	Miguel 60 Tap	Miguel	138.00	138.00	1S		0.95	2
35	Miguel 60 Tap	Z119793	138.00	138.00	1S	0.02		1
36					TOTAL	1,445.94	668.24	511

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	04/17/2020	End of 2019/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Z119793	Z200591	138.00	138.00	1S,2S	0.50		1
2			138.00	138.00	1S,3		13.49	2
3		Los Coches	138.00	138.00	1S,3		1.41	2
4	Batiquitos		138.00	138.00	1S		2.61	2
5		Shadowridge	138.00	138.00	1S		3.73	2
6	Miguel		138.00	138.00	1S	0.72		1
7		Proctor Valley	138.00	138.00	1S,3		0.61	2
8	Friars		138.00	138.00	4	0.09		1
9		Mission	138.00	138.00	1S,3		1.26	2
10	Sycamore		138.00	138.00	1S		3.85	2
11			138.00	138.00	1S		1.78	2
12		Carlton Hills	138.00	138.00	1S,3		1.48	2
13	Trabuco		138.00	138.00	1S	0.68		1
14			138.00	138.00	1S	0.08		1
15			138.00	138.00	4	3.03		1
16		Margarita	138.00	138.00	4	0.23		1
17	Talega	Rancho Mission Viejo	138.00	138.00	1W,1S	6.42		1
18	Trabuco		138.00	138.00	1W,1S	3.66		1
19			138.00	138.00	1W,3		0.16	2
20			138.00	138.00	1S,3		6.34	2
21		Pico	138.00	138.00	4		0.32	2
22	Capistrano		138.00	138.00	1W	3.59		1
23		Trabuco	138.00	138.00	1W		0.15	2
24	San Mateo	Talega	138.00	138.00	1W,1S	1.29		1
25	Talega Tap		138.00	138.00	1W,3		2.96	2
26			138.00	138.00	1W,2W,1S,2S,	8.10		1
27			138.00	138.00	4		1.84	2
28		Laguna Niguel	138.00	138.00	4	0.35		1
29	Pico		138.00	138.00	1S,3		0.70	2
30		Talega	138.00	138.00	1W	0.41		1
31	Capistrano		138.00	138.00	1W	0.01		1
32			138.00	138.00	1W		0.15	2
33			138.00	138.00	1W,1S	1.36		1
34		Laguna Niguel	138.00	138.00	4		1.84	2
35	Rancho Mission Viejo	Margarita	138.00	138.00	1W,1S	3.06		1
36					TOTAL	1,445.94	668.24	511

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Mission		138.00	138.00	1W,1S	2.56		1
2		Grant Hill	138.00	138.00	4	2.84		1
3	Cannon	Encina Hub	138.00	138.00	1S,3		1.29	2
4	Encina Hub	Shadowridge	138.00	138.00	1S,2S,2W	6.73		1
5	East County		138.00	138.00	1S,2S	6.99		1
6			138.00	138.00	4	5.54		1
7			138.00	138.00	4	1.12		1
8		Boulevard East	138.00	138.00	4	0.18		1
9	Pico		138.00	138.00	3		0.70	2
10		Talega	138.00	138.00	1W,1S	0.47		1
11	Talega		138.00	138.00	3		2.78	2
12		San Mateo	138.00	138.00	1S		0.73	2
13	Encina	Z124528	138.00	230.00	1S		0.04	2
14	Z124528	Cannon	138.00	230.00	1S		0.11	2
15	Boulavard	Boulevard East	238.00	138.00	4		0.99	1
16	East County	Eco Gen 2	138.00	138.00	1S	0.33		1
17	Encina	Encina Gen 1	138.00	138.00	3S	0.03		1
18	13822	De-Energized	138.00	138.00	2W	0.06		1
19	13832	De-Energized	138.00	138.00	3,1S,1W	3.36		1
20	13832	De-Energized	138.00	138.00	3,1S,1W	3.21		1
21	13811	De-Energized	138.00	138.00	1S	1.07		1
22	13811	De-Energized	138.00	138.00	3	5.69		1
23	Cannon	Encina Hub	138.00	138.00	1S,3		1.28	2
24	Encina Hub	Calavera Tap	138.00	138.00	2W	0.39		1
25	Encina Hub	Calavera Tap	138.00	138.00	2W	2.94		1
26	Calavera Tap	San Luis Rey	138.00	138.00	2W	3.89		1
27	Bay Blvd		138.00	138.00	3		2.82	2
28		Telegraph Canyon	138.00	138.00	3		2.98	2
29	Total 138kV Pole Line Mi					141.26	117.66	170
30					1W	706.78	25.40	125
31					2W	7.11	1.38	
32					1S	43.23	1.50	
33					3	20.00	50.61	
34					4	62.10	0.60	
35	Total of 69kV Pole Line Mi					839.22	79.49	125
36					TOTAL	1,445.94	668.24	511

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	04/17/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	Cost of Line							
3	Expenses, Except ISO Charge							
4	ISO Charges							
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,445.94	668.24	511

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-2156 ACSR								1
2-2156 ACSR								2
2-2156 ACSR								3
3-1033.5 ACSR								4
2-2156 ACSR								5
3-1033.5 ACSR								6
2-1590 ACSR								7
								8
1-1033.5 ACSR/AW								9
1-1033.5 ACSR/AW								10
1-5000 KCMIL CU								11
2-1033.5 ACSR/AW								12
2-1033.5 ACSR/AW								13
2-1033.5 ACSR/AW								14
2-1033.5 ACSR/AW								15
2-1109 ACAR								16
1-1033.5 ACSR/AW								17
1-1033.5 ACSR/AW								18
1-5000 KCMIL CU E								19
1-1033.5 ACSR/AW								20
1-1033.5 ACSR/AW								21
2-1033.5 ACSR/AW								22
1-1033.5 ACSR/AW								23
2-1033.5 ACSR/AW								24
2-1033.5 ACSR/AW								25
2-1033.5 ACSR/AW								26
2-1033.5 ACSR/AW								27
2-1033.5 ACSR/AW								28
2-1033.5 ACSR/AW								29
2-1109 ACAR								30
2-1109 ACAR								31
2-1109 ACAR								32
2-900 ACSS/AW								33
2-1109 ACAR								34
2-1109 ACAR								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	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	04/17/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-1033.5 ACSR/AW								1
2-1033.5 ACSR/AW								2
2-1109 ACAR								3
2-900 ACSS/AW								4
2-605 ACSS/AW								5
2-900 ACSS/AW								6
2-605 ACSS/AW								7
2-1113 ACSS/AW								8
2-900 ACSS/AW								9
2-1033.5 ACSR/AW								10
2-605 ACSS/AW								11
2-900 ACSS/AW								12
2-605 ACSS/AW								13
2-636 ACSS/AW								14
2-1033.5 ACSR/AW								15
2-1109 ACAR								16
1-1109 ACAR								17
2-605 ACSS/AW								18
2-1109 ACAR								19
2-1033.5 ACSR/AW								20
2-636 ACSS/AW								21
2-3500 KCMIL CU								22
2-4000 KCMIL CU								23
2-900 ACSS/AW								24
2-1109 ACAR								25
1-1109 ACAR								26
2-1109 ACAR								27
1-1109 ACAR								28
1-3500 KCMIL CU								29
1-2500 KCMIL CU								30
1-3500 KCMIL CU								31
1-2500 KCMIL CU								32
1-1033.5 ACSR/AW								33
1-1033.5 ACSR/AW								34
1-1033.5 ACSR/AW								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	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	04/17/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-900 ACSS/AW								1
2-1033.5 ACSR/AW								2
2-900 ACSS/AW								3
2-1033.5 ACSR/AW								4
2-605 ACSS/AW								5
2-1109 ACAR								6
2-900ACSS/AW								7
2-900ACSS/AW								8
2-5000 KCMIL CU								9
2-1033.5 ACSS/AW								10
2-1113 ACSR								11
2-1113 ACSR								12
2-954 AL								13
2-954 AL								14
2-900 ACSS/AW								15
2-900 ACSS/AW								16
2-1109 ACAR								17
2-1109 ACAR								18
2-1033.5 ACSR/AW								19
2-1033.5 ACSR/AW								20
2-1033.5 ACSR/AW								21
1-1033.5 ACSR/AW								22
2-1033.5 ACSR/AW								23
2-1109 ACAR								24
2-1033.5 ACSR/AW								25
2-900 ACSS/AW								26
2-4000 KCMIL CU								27
2-900 ACSS/AW								28
2-4000 KCMIL CU								29
2-900 ACSS/AW								30
2-900 ACSS/AW								31
2-900 ACSS/AW								32
2-900 ACSS/AW								33
2-900 ACSS/AW								34
2-900 ACSS/AW								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	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	04/17/2020	End of 2019/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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
2-900 ACSS/AW								1
1-1272 ACSS								2
2-900 ACSS/AW								3
2-4000 KCMIL CU								4
2-4000 KCMIL CU E								5
2-5000 KCMIL CU E								6
1-3500 CU								7
2-1033.5 ACSR/AW								8
1-5000 KCMIL CU								9
2-1033.5 ACSR/AW								10
1-5000 KCMIL CU								11
2-900 ACSS/AW								12
2-1033.5 ACSR/AW								13
1-1033.5 ACSR/AW								14
2-1113 ACSS/AW								15
2-900 ACSS/AW								16
2-900 ACSS/AW								17
								18
2-1033.5 ACSR/AW								19
2-1109 ACAR								20
2-1109 ACAR								21
2-636 ACSR/AW								22
1-1750 MCM AL								23
2-1750 MCM AL								24
2-1033.5 ACSR/AW								25
2-1033.5 ACSR/AW								26
2-1109 ACAR								27
2-1109 ACAR								28
2-1033.5 ACSR/AW								29
2-636 ACSS/AW								30
2-2500 CU								31
1-636 ACSR/AW								32
1-400 MCM CU								33
1-636 ACSR/AW								34
1-636 ACSR/AW								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	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	04/17/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1-336 ACSR/AW								1
1-336 ACSR/AW								2
1-1033.5 ACSR/AW								3
1-250 MCM CU								4
1-336 ACSR/AW								5
2-1033.5 ACSR/AW								6
1-636 ACSR/AW								7
2-1033.5 ACSR/AW								8
2-636 ACSR/AW								9
1-2500 KCMIL CU								10
1-1033.5 ACSR/AW								11
2-400 MCM CU								12
2-636 ACSS/AW								13
2-636 ACSR/AW								14
1-1033.5 ACSR/AW								15
1-1033.5 ACSR/AW								16
1-636 ACSR/AW								17
1-1750 MCM CU								18
1-1033.5 ACSR/AW								19
1-605 ACSS/AW								20
2-336 ACSR/AW								21
2-636 ACSR/AW								22
1-3000 KCMIL CU								23
1-636 ACSR/AW								24
1-900 ACSS/AW								25
1-900 ACSS/AW								26
2-336.4 ACSR								27
2-336.4 ACSR								28
4-336.4 MCM								29
1-900 ACSS/AW								30
2-1033.5 ACSR/AW								31
2-636 ACSR/AW								32
2-636 ACSR/AW								33
2-900 ACSS/AW								34
2-636 ACSS/AW								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-636 ACSR/AW								1
1-636 ACSS/AW								2
1-636 ACSR/AW								3
2-1033.5 ACSR/AW								4
2-1033.5 ACSR/AW								5
2-636 ACSS/AW								6
2-636 ACSR/AW								7
1-1750 KCMIL AL								8
1-900 ACSS/AW								9
1-900 ACSS/AW								10
1-900 ACSS/AW								11
1-900 ACSS/AW								12
1-1033.5 ACSR/AW								13
2-1033.5 ACSR/AW								14
1-1750 KCMIL AL								15
1-1750 KCMIL CU								16
1-1033.5 ACSR/AW								17
1-1033.5 ACSR/AW								18
1-1033.5 ACSR/AW								19
1-1033.5 ACSR/AW								20
1-1750 MCM CU								21
1-1033.5 ACSR/AW								22
1-1033.5 ACSR/AW								23
1-1033.5 ACSR/AW								24
1-336.4 ACSR/AW								25
1-336.4 ACSR/AW								26
1-1750 KCMIL AL								27
1-1750 KCMIL AL								28
1-900 ACSS/AW								29
1-1033.5 ACSR/AW								30
1-636 ACSR/AW								31
1-336.4 ACSR/AW								32
1-336.4 ACSR/AW								33
1-1750 KCMIL AL								34
1-1033.5 ACSR/AW								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	36

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)	
2-636 ACSR/AW								1
1-2500 MCM CU								2
2-1109 ACAR								3
1-900 ACSS/AW								4
2-900 ACSS/AW								5
2-2500 KCMIL CU								6
2-3000 KCMIL CU								7
2-5000 KCMIL CU								8
1-1033.5 ACSR/AW								9
1-1033.5 ACSR/AW								10
1-336.4 ACSR/AW								11
1-1033.5 ACSR/AW								12
2-1033.5 ACSR								13
2-1109 ACAR								14
2-2500 KCMIL CU								15
1-636 ACSR/AW								16
1-636 KCMIL ACSR								17
1-1109 ACAR								18
1-336.4 ACSR								19
1-250 MCM CU								20
1-900 ACSS/AW								21
1-250 MCM CU								22
2-1109 ACAR								23
1-1033.5 ACSR/AW								24
1-636 ACSS/AW								25
1-1033.5 ACSR/AW								26
2-636 ACSR/AW								27
2-400 MCM CU								28
								29
								30
								31
								32
								33
								34
								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	36

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)	
								1
	205,126,609	3,680,008,465	3,885,135,074					2
				15,849,623	20,136,769	2,829,825	38,816,217	3
				2,934,251			2,934,251	4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	205,126,609	3,680,008,465	3,885,135,074	18,783,874	20,136,769	2,829,825	41,750,468	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	04/17/2020	2019/Q4

FOOTNOTE DATA

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 Colorado River. SDG&E owns 76.22% and 85.64%, respectively, while Arizona Public Service owns 23.78% and 14.36%, respectively.

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	04/17/2020	End of 2019/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	Loveland	Barrett	7.43	OH	10.00	1	1
4							
5	Clairmont	Mission	3.88	OH	17.00	1	1
6							
7	Miguel	Bay Blvd	9.65	OH	5.00	2	2
8							
9	Rincon	Warners	19.99	OH	12.00	1	1
10							
11	UNDERGROUND						
12							
13	Clairmont	Mission	0.52	UG		1	1
14							
15	Bernardo	Rancho Carmel	2.97	UG		1	1
16							
17	Ocean Ranch	Melrose	0.20	UG		1	1
18							
19	Z100477	Bay Blvd	0.17	UG		1	1
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	TOTAL		44.81		44.00	9	9

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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
1-636	ACSS/AW	9	69	2,623,271	14,193,128	3,914,972	193,099	20,924,470	3
									4
1-900	ACSS/AW	6	69		15,753,060	6,499,881	651,825	22,904,766	5
									6
2-900	ACSS/AW	18	230		2,863,179	8,425,014	808,984	12,097,177	7
									8
1-636	ACSS/AW	9	69	5,047,673	49,769,908	13,459,109	902,976	69,179,666	9
									10
									11
									12
1-3000	KCMIL U	8	69			11,207,716		11,207,716	13
									14
1-3000	KCMIL G	8	69			42,029,075		42,029,075	15
									16
1-3000	KCMIL U	8	69			4,134,501		4,134,501	17
									18
2-5000	KCMIL U	8	230			4,269,136		4,269,136	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
				7,670,944	82,579,275	93,939,404	2,556,884	186,746,507	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) 04/17/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 3 Column: c

To report re-build of 7.43 miles for TL6957 from Loveland to Barrett for 2019.

Schedule Page: 424 Line No.: 5 Column: c

To report re-build of 3.88 miles for TL600/676 from Clairmont to Rose Canyon and Mesa Heights to Mission for 2019.

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

To report addition of 9.65 miles for TL23020 from Miguel to Bay Boulevard for 2019.

Schedule Page: 424 Line No.: 9 Column: c

To report addition of 3.16 miles for TL663 from Mission to Kearny West for 2019.

Schedule Page: 424 Line No.: 13 Column: c

To report re-build of 0.94 miles for TL600/676 from Clairmont to Rose Canyon and Mesa Heights to Mission for 2019.

Schedule Page: 424 Line No.: 15 Column: c

To report addition of 2.97 miles for TL633 from Bernardo to Rancho Carmel for 2019.

Schedule Page: 424 Line No.: 17 Column: c

To report addition of 0.20 miles for TL6979 from Ocean Ranch to Melrose for 2019.

Schedule Page: 424 Line No.: 19 Column: c

To report addition of 0.17 miles for TL23042 from Structure Z100477 to Bay Boulevard for 2019.

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	04/17/2020	End of 2019/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	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	04/17/2020	End of 2019/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	KEARNY WEST, San Diego	Dist. Unattended	69.00	12.00	
21	KETTNER, San Diego	Dist. Unattended	69.00	12.00	
22	KYOCERA, San Diego	Dist. Unattended	69.00	12.00	
23	LA JOLLA, La Jolla	Dist. Unattended	69.00	12.00	
24	LAGUNA NIGUEL, Laguna Niguel	Dist. Unattended	138.00	12.00	
25	LAS PULGAS, Oceanside	Dist. Unattended	69.00	12.00	
26	LILAC, Valley Center	Dist. Unattended	69.00	12.00	
27	LINCOLN ACRES, National City	Dist. Unattended	12.00	4.00	
28	LOS COCHES, Lakeside	Dist. Unattended	69.00	12.00	
29	LOVELAND, Alpine	Dist. Unattended	69.00	12.00	
30	MARGARITA, Mission Viejo	Dist. Unattended	138.00	12.00	
31	MELROSE, Vista	Dist. Unattended	69.00	12.00	
32	MESA HEIGHTS, San Diego	Dist. Unattended	69.00	12.00	
33	MESA RIM, San Diego	Dist. Unattended	69.00	12.00	
34	MIRAMAR, San Diego	Dist. Unattended	69.00	12.00	
35	MIRA SORRENTO, San Diego	Dist. Unattended	69.00	12.00	
36	MISSION, San Diego	Dist. Unattended	69.00	12.00	
37	MONSERATE, Fallbrook	Dist. Unattended	69.00	12.00	
38	MONTGOMERY, Chula Vista	Dist. Unattended	69.00	12.00	
39	MORRO HILL, Oceanside	Dist. Unattended	69.00	12.00	
40	MURRAY, La Mesa	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	04/17/2020	End of 2019/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	NATIONAL CITY, National City	Dist. Unattended	69.00	4.00	12.00
2	NAVAL STATION Switchyard, San Diego-NSM	Dist. Unattended	69.00		
3	NORTH CITY WEST, San Diego	Dist. Unattended	69.00	12.00	
4	NORTH VISTA,Vista	Dist. Unattended	12.00	4.00	
5	OCEAN RANCH, Oceanside	Dist. Unattended	69.00	12.00	
6	OCEANSIDE, Oceanside	Dist. Unattended	69.00	12.00	
7	OLD TOWN, San Diego	Dist. Unattended	69.00	12.00	
8	OLIVENHAIN, Escondido	Dist. Unattended	69.00	12.00	
9	OTAY LAKES, Chula Vista	Dist. Unattended	69.00	12.00	
10	OTAY, Chula Vista	Dist. Unattended	69.00	12.00	
11	PACIFIC BEACH, San Diego	Dist. Unattended	69.00	12.00	
12	PALA, San Diego County	Dist. Unattended	69.00	12.00	
13	PALOMAR AIRPORT, Carlsbad	Dist. Unattended	138.00	12.00	
14	PARADISE, San Diego	Dist. Unattended	69.00	12.00	
15	PENDLETON, Oceanside	Dist. Unattended	69.00	12.00	
16	PICO, San Clemente	Dist. Unattended	138.00	12.00	
17	POINT LOMA SEWAGE, San Diego	Dist. Unattended	12.00	4.00	
18	POINT LOMA, San Diego	Dist. Unattended	69.00	12.00	
19	POMERADO, San Diego	Dist. Unattended	69.00	12.00	
20	POWAY, Poway	Dist. Unattended	69.00	12.00	
21	PROCTOR VALLEY, Bonita	Dist. Unattended	138.00	12.00	
22	RAMONA, Ramona	Dist. Unattended	12.00	4.00	
23	RANCHO CARMEL, San Diego	Dist. Unattended	69.00	12.00	
24	RANCHO MISSION VIEJO, Rancho Mission Viejo	Dist. Unattended	138.00	12.00	
25	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	12.00	
26	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	4.00	
27	RINCON, Rincon	Dist. Unattended	69.00	12.00	
28	ROLANDO, San Diego	Dist. Unattended	12.00	4.00	
29	ROSE CANYON, San Diego	Dist. Unattended	69.00	12.00	
30	SALT CREEK, Chula Vista	Dist. Unattended	69.00	12.00	
31	SAMPSON, San Diego	Dist. Unattended	69.00	12.00	
32	SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
33	SAN LUIS REY, Oceanside	Dist. Unattended	69.00	12.00	
34	SAN MARCOS, San Marcos	Dist. Unattended	69.00	12.00	
35	SAN MATEO, San Clemente	Dist. Unattended	138.00	12.00	
36	SAN YSIDRO, San Ysidro	Dist. Unattended	69.00	12.00	
37	SANTA YSABEL, Santa Ysabel	Dist. Unattended	69.00	12.00	
38	SANTEE, Santee	Dist. Unattended	138.00	12.00	
39	SCRIPPS, San Diego	Dist. Unattended	69.00	12.00	
40	SEWAGE PUMP STA (3)., San Diego	Dist. Unattended	12.00	4.00	

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	04/17/2020	End of 2019/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	SHADOWRIDGE, Vista	Dist. Unattended	138.00	12.00	
2	SHORECLIFFS, San Clemente	Dist. Unattended	12.00	4.00	
3	SOUTH SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
4	SPRING VALLEY, Spring Valley	Dist. Unattended	69.00	12.00	
5	STREAMVIEW, San Diego	Dist. Unattended	69.00	12.00	
6	STUART, Oceanside	Dist. Unattended	69.00	12.00	
7	SUNNYSIDE, San Diego	Dist. Unattended	69.00	12.00	
8	SWEETWATER, National City	Dist. Unattended	69.00	12.00	
9	TELEGRAPH CANYON, Chula Vista	Dist. Unattended	138.00	12.00	
10	TORREY PINES, San Diego	Dist. Unattended	69.00	12.00	
11	TRABUCO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
12	UCM switchyard, San Diego	Dist. Unattended	69.00		
13	URBAN, San Diego	Dist. Unattended	69.00	12.00	
14	VALLEY CENTER, Valley Center	Dist. Unattended	69.00	12.00	
15	VINE	Dist. Unattended	69.00	12.00	
16	VISTA, Vista	Dist. Unattended	12.00	4.00	
17	WARNERS, Warner Springs	Dist. Unattended	69.00	12.00	
18	WARREN CANYON, Poway	Dist. Unattended	69.00	12.00	
19	WARREN CANYON, Poway	Dist. Unattended	69.00	4.00	
20	WITHERBY, San Diego	Dist. Unattended	12.00	4.00	
21	BAY BOULEVARD	Trans. Unattended	230.00	69.00	
22	DOUBLETT switchyard, San Diego	Trans. Unattended	138.00	69.00	
23	EAST COUNTY, Boulevard	Trans. Unattended	500.00	230.00	12.00
24	EAST COUNTY, Boulevard	Trans. Unattended	230.00	138.00	
25	ENCINA switchyard, Carlsbad	Trans. Unattended	138.00		
26	ENCINA, Carlsbad	Trans. Unattended	230.00	138.00	
27	ESCONDIDO, Escondido	Trans. Unattended	230.00	69.00	
28	GOAL LINE, Escondido	Trans. Unattended	69.00		
29	IMPERIAL VALLEY, El Centro	Trans. Unattended	500.00	230.00	12.00
30	LOS COCHES, Lakeside	Trans. Unattended	138.00	69.00	
31	MIGUEL, Bonita	Trans. Unattended	230.00	69.00	
32	MIGUEL, Bonita	Trans. Unattended	230.00	138.00	
33	MIGUEL, Bonita	Trans. Unattended	500.00	230.00	12.00
34	MIRAMAR GT, San Diego	Trans. Unattended	12.00	69.00	
35	MISSION, San Diego	Trans. Unattended	138.00	69.00	
36	MISSION, San Diego	Trans. Unattended	230.00	69.00	
37	MISSION, San Diego	Trans. Unattended	230.00	138.00	
38	NARROWS, Borrego Springs	Trans. Unattended	88.00	69.00	12.00
39	OCOTILLO switchyard, Ocotillo	Trans. Unattended	500.00		
40	OLD TOWN, San Diego	Trans. Unattended	230.00	69.00	

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	OTAY MESA switchyard, Chula Vista	Trans Unattended	230.00		
2	PENASQUITOS, San Diego	Trans. Unattended	138.00	69.00	
3	PENASQUITOS, San Diego	Trans. Unattended	230.00	138.00	
4	PENASQUITOS, San Diego	Trans. Unattended	230.00	69.00	
5	SAN LUIS REY, Oceanside,	Trans. Unattended	230.00	69.00	
6	SILVERGATE, San Diego	Trans. Unattended	230.00	69.00	
7	SONGS	Trans. Unattended	230.00	230.00	
8	SUNCREST, Japatul	Trans. Unattended	500.00	230.00	12.00
9	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	69.00	
10	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	138.00	
11	TALEGA, San Clemente	Trans. Unattended	138.00	69.00	
12	TALEGA, San Clemente	Trans. Unattended	230.00	138.00	
13	WABASH switchyard, San Diego	Trans. Unattended	69.00		
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					

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	04/17/2020	End of 2019/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

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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
112	4	1				20
56	2					21
9	1					22
56	2					23
112	4					24
28	1					25
56	2					26
6	1					27
84	3					28
28	1					29
112	4					30
112	4					31
84	3					32
112	4					33
84	3					34
56	2					35
112	4					36
56	2					37
56	2					38
13	1					39
112	4	1				40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	2					1
						2
56	2					3
3	1					4
56	2					5
56	2					6
84	3	2				7
28	1					8
5	1					9
56	2	1				10
56	2					11
28	1					12
84	3					13
56	2					14
56	2					15
56	2					16
13	1					17
84	3					18
84	3					19
56	2					20
56	2	1				21
6	1					22
84	3					23
56	2					24
41	2					25
6	1					26
25	2					27
13	2					28
56	2					29
56	2					30
112	4					31
3	1					32
112	4					33
112	4					34
45	2					35
56	2					36
12	1					37
56	2					38
84	3					39
46	6					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
84	3					1
3	1					2
3	1					3
56	2					4
56	2					5
8	1					6
28	1					7
56	2	1				8
112	4					9
112	4					10
112	4					11
						12
84	3					13
28	1					14
56	3					15
10	2					16
28	1					17
8	1					18
7	1					19
6	1					20
448	2					21
						22
1120	1					23
392	1					24
						25
784	2					26
672	3					27
						28
2840	9	2				29
448	2					30
448	2					31
784	2					32
2240	6	1	500/17	2	500	33
50	1					34
200	1					35
224	1					36
784	2					37
10	3					38
						39
448	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
520	3					2
392	1	1				3
448	2					4
672	3		230/17	2	500	5
448	2	1				6
250			230/17	1	250	7
2240	6	1				8
672	3	1				9
392	1	1				10
140	1	1				11
1102	4		230/17	2	500	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

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	04/17/2020	End of 2019/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	10,157,696
3	Accumulated provision for depreciation of Electrit	Sempra Energy	108	69
4	Other Utility Plant	Sempra Energy	118	69,551
5	Other Accounts Receivable	Sempra Energy	143	-673,764
6	Accounts Receivable from Associated Companies	Sempra Energy	146	4,548
7	Stores Expense Undistributed	Sempra Energy	163	5,493
8	Prepayments	Sempra Energy	165	144,581,326
9	Unamortized Debt Expense	Sempra Energy	181	652,666
10	Other regulatory assets	Sempra Energy	182	383,350
11	Preliminary Survey and Investigation Charges	Sempra Energy	183	-166
12	Clearing Accounts	Sempra Energy	184	4,339,759
13	Miscellaneous Deferred Debits	Sempra Energy	186	384,816
14	Accumulated Other Comprehensive Income	Sempra Energy	219	165,881
15	Accumulated Provision for Pensions and Benefits	Sempra Energy	228.3	-280,509
16	Accumulated miscellaneous operating provisions	Sempra Energy	228.4	71,115
17	Accounts Payable	Sempra Energy	232	465,341
18	Other regulatory liabilities.	Sempra Energy	254	-383,350
19	Expenditures for Certain Civic, Political and Rels	Sempra Energy	426.4	787,713
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounting & Finance	Sempra Energy	146	2,166,544
22	Depreciation Expense	Sempra Energy	146	441,564
23	Engineering / Const. Services	Sempra Energy	146	10,507
24	Environmental Services	Sempra Energy	146	20,468
25	External Affairs	Sempra Energy	146	347,031
26	Fleet Services	Sempra Energy	146	34,448
27	Human Resources	Sempra Energy	146	4,821,449
28	Information Technology	Sempra Energy	146	3,933,276
29	Real Estate & Facilities	Sempra Energy	146	4,291,061
30	Supply Management	Sempra Energy	146	1,496,982
31	Accounting & Finance	North American Infrastructure	146	26,729
32	Depreciation Expense	North American Infrastructure	146	37,084
33	Environmental Services	North American Infrastructure	146	78
34	Human Resources	North American Infrastructure	146	296,764
35	Information Technology	North American Infrastructure	146	76,771
36	Real Estate & Facilities	North American Infrastructure	146	99,425
37	Supply Management	North American Infrastructure	146	102,238
38	Accounting & Finance	Southern California Gas Company	146	33,938,481
39	Customer Services	Southern California Gas Company	146	340,911
40	"DepreciationExpense"	Southern California Gas Company	146	4,810,850
41	Engineering and Construction Services	Southern California Gas Company	146	491,710
42	Environmental Services	Southern California Gas Company	146	249,844
1	**Non-power Goods or Services Provided by Affiliated**			
2	Other Electric Revenues	Sempra Energy	456	51,300

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	1,892
4	Miscellaneous Steam Power Expenses	Sempra Energy	506	864
5	Maintenance of miscellaneous steam plant	Sempra Energy	514	521
6	Operation Supervision and Engineering	Sempra Energy	546	337
7	Miscellaneous Other Power Generation Expenses	Sempra Energy	549	22
8	Maintenance of miscellaneous other power generatit	Sempra Energy	554	2,732
9	System control and load dispatching	Sempra Energy	556	130
10	Other expenses	Sempra Energy	557	1,172
11	Power Transmission Operation Supervision and Engig	Sempra Energy	560	3,977
12	Load Dispatch	Sempra Energy	561	1,680
13	Station expenses	Sempra Energy	562	1,160
14	Miscellaneous Transmission Expenses	Sempra Energy	566	202,950
15	Maintenance of Structures	Sempra Energy	569	6,436
16	Maintenance of Station Equipment	Sempra Energy	570	1,250
17	Maintenance Overhead Lines	Sempra Energy	541	2,063
18	Oper & Engr Supv	Sempra Energy	580	44,225
19	Load dispatching	Sempra Energy	581	2,493
20	**Non-power Goods or Services Provided for Affiliate**			
21	External Affairs	Southern California Gas Company	146	2,462,847
22	Fleet Services	Southern California Gas Company	146	-11,546
23	Human Resources	Southern California Gas Company	146	1,540,026
24	Information Technology	Southern California Gas Company	146	51,482,513
25	Real Estate & Facilities	Southern California Gas Company	146	1,943,978
26	Supply Management	Southern California Gas Company	146	1,039,145
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Underground line expenses	Sempra Energy	584	145
3	Meter Expenses	Sempra Energy	586	9,050
4	Customer installations expenses	Sempra Energy	587	24

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	04/17/2020	End of 2019/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)
5	Miscellaneous Distribution Expenses	Sempra Energy	588	840,249
6	Maintenance Supervision	Sempra Energy	590	1,059
7	Maintenance of Station Equipment	Sempra Energy	592	88
8	Maintenance of Overhead Lines	Sempra Energy	593	7,164
9	Maintenance of Meters	Sempra Energy	597	154
10	Operation Supervision and Engineering	Sempra Energy	850	1,761
11	Communication System Expenses	Sempra Energy	853	296
12	Mains expenses.	Sempra Energy	856	89
13	Maintenance of Mains	Sempra Energy	863	408,689
14	Maintenance of measuring and regulating station e.	Sempra Energy	865	265
15	Operation Supervision and Engineering	Sempra Energy	870	48,160
16	Mains and services expenses	Sempra Energy	874	8,596
17	Measuring and regulating station expenses—General.	Sempra Energy	875	198
18	Customer Installations Expenses	Sempra Energy	879	23,893
19	Distribution Other Expenses	Sempra Energy	880	16,561
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Maintenance of Mains	Sempra Energy	887	2,502
3	Maintenance of other equipment.	Sempra Energy	894	84
4	Meter Reading Expenses	Sempra Energy	902	6,060
5	Customer Records and Collection Expenses	Sempra Energy	903	35,459
6	Customer Assistance Expenses	Sempra Energy	908	18,940

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	04/17/2020	End of 2019/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)
7	Miscellaneous Customer Service and Informational s	Sempra Energy	910	803,058
8	Office Supplies and Expenses	Sempra Energy	921	715,958
9	Outside Services Employed	Sempra Energy	923	64,937,347
10	Property Insurance	Sempra Energy	924	312,649
11	Injuries and Damages	Sempra Energy	925	25,295,474
12	Employee Pension and Benefits	Sempra Energy	926	46,862,300
13	Regulatory Commission Expenses	Sempra Energy	928	727,221
14	Miscellaneous General Expense	Sempra Energy	930.2	-516,369
15	Maintenance of General Plant	Sempra Energy	935	9,529
16	Purchased Power	Energia Sierra Juarez	555	51,345,777
17	Construction Work in Progress	Southern California Gas Company	107	6,564,386
18	Other Utility Plant	Southern California Gas Company	118	3,553,999
19	3rd Party Bill A/R-Clearing	Southern California Gas Company	143.8	5,166
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Stores Expense Undistributed	Southern California Gas Company	163	563,399
3	Clearing Accounts	Southern California Gas Company	184	1,625,198
4	Miscellaneous Deferred Debits	Southern California Gas Company	186	551
5	Accounts Payable	Southern California Gas Company	232	8,504
6	Expense of Non Utility Operations	Southern California Gas Company	417	172,223
7	Expenditures for Certain Civic, Political and Rels	Southern California Gas Company	426.4	8,776
8	Other Gas Revenues	Southern California Gas Company	495	-152,915

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	04/17/2020	End of 2019/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)
9	ET Operations Executive Comp	Southern California Gas Company	560	14,401
10	Miscellaneous Transmission Expenses	Southern California Gas Company	566	4,469
11	Miscellaneous Distribution Expenses	Southern California Gas Company	588	25,257
12	Natural Gas TR Line Prch	Southern California Gas Company	803	2,919
13	GTO Operations Supervision & Engineering	Southern California Gas Company	850	4,280,401
14	System Control & Load Dispatch	Southern California Gas Company	851	738,189
15	Communication System Expenses	Southern California Gas Company	853	2,190
16	Other Expenses	Southern California Gas Company	859	37,820
17	GTM Maintenance Mains	Southern California Gas Company	863	1,000,734
18	Operation Supervision and Engineering	Southern California Gas Company	870	4,132,853
19	Routine Leak Survey	Southern California Gas Company	874	41,420
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Distribution Other Expenses	Southern California Gas Company	880	56,367
3	GDM Maintenance Mains	Southern California Gas Company	887	126,373
4	Maintenance / Meters & Hse Reg	Southern California Gas Company	893	243,537
5	Meter Reading Expenses	Southern California Gas Company	902	140,227
6	Customer Records and Collection Expenses	Southern California Gas Company	903	2,955,894
7	Customer Assistance Expenses	Southern California Gas Company	908	938,645
8	Informational and Instructional Advertising Expens	Southern California Gas Company	909	468
9	Miscellaneous Customer Service and Informational s	Southern California Gas Company	910	279,752
10	Administrative and General Salaries	Southern California Gas Company	920	5,921

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	Office Supplies and Expenses	Southern California Gas Company	921	4,167
12	Outside Services Employed	Southern California Gas Company	923	51,171,910
13	Injuries and Damages	Southern California Gas Company	925	443,914
14	Employee Pension and Benefits	Southern California Gas Company	926	71,756
15	Regulatory Commission Expenses	Southern California Gas Company	928	2,015,409
16	Miscellaneous General Expense	Southern California Gas Company	930.2	201,500
17	Rents	Southern California Gas Company	931	874,562
18	Maintenance of General Plant	Southern California Gas Company	935	465,793
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

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

1 (Rows 1-109)
All non-power goods and services provided by affiliated companies are billed to San Diego Gas and Electric at fully loaded cost.

2 (Rows 2-70)
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 basic without ONCOR, 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 (EXCLUDES ONCOR); 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 split without ONCOR, 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(EXCLUDES ONCOR); 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; 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 - Legal, this method is weighted average of annual labor budget for departments that report to the Executive Vice President & General Counsel; Average - CFO, this method is a weighted average of annual labor budget for departments that report to the CFO; 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; Average - Vice President of Audit Services, this method is a weighted average of annual labor budget for departments that report to the VP of Audit Services; Average - Vice President of Corporate Development & Technology, This method is a weighted average of annual labor budget for departments that report to the Vice President of Corporate Development & Technology; Average - Vice President of Corporate Communications and Sustainability, This method is a weighted average of annual labor budget for the departments that report to the Vice President of Corporate Communications and Sustainability; 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 at Sempra Energy Corporate Center; 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%)

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	(Mo, Da, Yr) 04/17/2020	2019/Q4

FOOTNOTE DATA

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; Causal - Fire Insurance, this method allocates all costs for Fire Insurance based on miles of electrical lines 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 workload is then re-allocated by Multi-factor (basic) to result in a blended percentage; 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 rate; 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 FTE's are reallocated by multi-factors; Causal - Sacramento Office Depreciation, Needs to be allocated by this method, San Diego Gas & Electric 50%, other affiliates 50%; 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 - Security Services, This method accounts for the call-in transportation services available to Corporate Officers and Executives. These call-in services are primarily provided to Corporate Officers and Executives at the California Utilities and for Mexico and South America. Occasionally, these services may be provided to Officers and Executives in other business units or at Sempra Energy Corporate Center. In this instance, these costs will be directly charged to the respective business unit or retained at Sempra Energy Corporate Center; Causal - Security Headquarters and Mission CSOC Depreciation, Need to be allocated by this method, San Diego Gas & Electric 84.3% other affiliates 15.7%; Causal - Major Projects & Controls, the Major Projects and Controls group allocates its overall costs based on a percentage of direct labor charges to each business segment for each month; and overall average is estimated for the Plan year; Causal - Major Projects Depreciation, Needs to be allocated by this method. San Diego Gas & Electric 16% other affiliates 84%; Causal - My Info Services Contract, My Info services cost is allocated by the number of people in the My Info system. The portion of services attributable to Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage; Causal - Pension, this method allocates based on the summary value of Sempra Energy's major pension savings funds and San Diego Gas & Electric's Nuclear Decommissioning Trust (NDT). The Sempra Energy Corporate Center and Sempra Global value is then re-allocated by the US-based FTE's, with Sempra Energy Corporate Center FTE's further re-allocated based on Multi-factor (basic); 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 work load hours are re-allocated using Multi-factor (basic) resulting in a blended percentage; Causal - Audit Plan, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit; 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; Causal - Audit US, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit; Causal - Audit Plan, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit; Causal - SOX, this allocation is a weighted average of the workload of each employee within SOX Compliance based on an annual time study. Sempra Energy Corporate Center workload hours are reallocated using Multi-Factor Basic, resulting in a blended percentage; Causal - Law Department, this allocation method is based on direct time charged by attorneys, paralegal and law clerks in the legal database during the previous August-July period. Hours for Sempra Energy Corporate Center are re-allocated by Multi-Factor Basic, resulting in a blended percentage; 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, and follow as such: Causal - Headquarters Occupancy, Rent, depreciation & ROR related to new headquarters that 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. Amenity floors in the HQ are excluded, as they benefit all occupants ratably; 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 - HQ Depreciation - depreciation expense & ROR related to "HQ leasehold improvements" is allocated based on the square footage directly occupied by the business units Corporate Center's direct occupation except for the portion which is retained, is re-allocated based on the Multi-Factor base allocation; Causal - Treasury Management System, Needs to be allocated by this method, San Diego Gas & Electric 21.1%, other affiliates 78.9%; 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 - Bank Reconciliations and Escheatment, for the Bank Reconciliation and Escheatment department, the estimated percentages of effort for the business units based on the bank reconciliation and escheatment activity for the upcoming period; Causal - Cash Management, for the Cash Management department, the Director estimates percentages based on volumes and time involved in the business units funding activities.

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

[3] (Rows 72-109)

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 131 Southern California Gas Company cost centers. The following causal beneficial relationship information is a summary of the 25 varying methodologies used: 23 cost centers used a form of miles of pipe installed and/or current year by service territory allocations; 19 cost centers used a form of LAN ID counts to determine the shared allocation; 16 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 9 cost centers used a form of allocation of computer and/or server system and resource usage statistics; 8 cost centers used a form of gas meter counts and service territory allocations; 7 cost centers used a form of departmental studies based on current year budgeted activities and/or dollars; 7 cost centers used a method involving the number of full time equivalent employees benefited by the activity; 6 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; 5 cost centers used a form of Full Time Employee equivalent statistics for support; 4 cost centers used a form of 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; 4 cost centers used a study based on cases worked by both regulated and non-regulated companies; 3 cost centers used a form of an employee matrix; 3 cost centers used a form of an allocation of space study identifying building square footage assigned; 2 cost centers used a form of a ratio of horsepower in compressor engines in the service territory; 2 cost centers used a form of a count of network sites; 2 cost centers used a meter ratio applied to specific budgeted activity; 2 cost centers used a form of unit of measurement of system gas flow throughput; 2 cost centers used a study based on the planned support level to Utilities; there was one use by a cost center of each of the remaining allocation methodologies: an internal department study based on volumes of items mailed and payments processed and the allocation of employee time; an allocation using

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

number of stakeholders at each utility; 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; a mileage ratio applied to specific budgeted activity; an estimate of hours worked on Diversity Reports; a unit of measurement of call volume; and, a workload study based on the number of claims processed over the last 5 years.

4 (Row 111-138)
All non-power goods and services provided by San Diego Gas and Electric are billed at fully loaded cost.

5 (Row 110)
Affiliate companies charged by San Diego Gas and Electric for less than $250,000 include: Sempra LNG, Sempra International South America, Sempra International Mexico, USA Gas & Power Renewables.

6 (Rows 111-138)
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 121 San Diego Gas and Electric cost centers. The following causal-beneficial relationship information is a summary of the 20 varying methodologies used: 29 cost centers used a form of LAN ID counts to determine the shared allocation; 27 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 16 cost centers used a form of an allocation of space study identifying building square footage assigned; 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; 8 cost centers use a form of workload distribution study; 5 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; 4 cost centers used a form of budgeted current year project assignments; 3 cost centers used a form of a count of network sites; 2 cost centers used a form of allocation of computer and/or server system and resource usage statistics; 2 cost centers used a form of allocation of voice count statistics; 2 Cost Centers were charged 100% to Sempra Energy Corporate Center; 2 cost centers used a form of Full Time Employee equivalent statistics for support; 2 cost centers used a form of the number of contracts supported; there was one use by a cost center of each of the remaining allocation methodologies: unit of measure based on San Diego Gas & Electric and Southern California Gas call volume; the number of full time equivalent employees benefited by the activity; the ratio of miles of pipe installed existing and/or current year by service territory allocations; cost centers used a form of allocation of application software login activity and statistics for active accounts; electric and gas meter counts and service territory allocations; number of user licenses available; 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 and current years budgeted activities by Affiliate.

INDEX

Schedule | Page No.

Schedule | Page No.

Schedule | Page No.

Document Content(s)