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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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**
Southern California Edison Company	**End of** 2015/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/eforms/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/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Southern California Edison Company	02 Year/Period of Report End of 2015/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)* 2244 Walnut Grove Avenue, Rosemead, California 91770	
05 Name of Contact Person Connie J. Erickson	06 Title of Contact Person VP & Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 2244 Walnut Grove Avenue, Rosemead, California 91770	

08 Telephone of Contact Person, *Including Area Code* (626) 302-1212	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/14/2016

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 Connie J. Erickson	03 Signature Connie J. Erickson	04 Date Signed *(Mo, Da, Yr)* 04/14/2016
02 Title VP & Controller		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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".

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

GENERAL INFORMATION

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

Ms. Connie J. Erickson, VP and Controller
Location: 2244 Walnut Grove Ave., Rosemead, CA 91770
Mailing address: P.O. Box 800, Rosemead, CA 91770

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, July 6, 1909

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 in receivership

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

Primarily engaged in eletric utility service in the state of California and gas and water service on Santa Catalina Island in the 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

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 beneficieraries for whom trust was maintained, and purpose of the trust.

Edison International holds control over respondent by

way of 100% ownership of respondent's common stock which was acquired

pursuant to a holding company reorganization effective July 1, 1988.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Bear Creek Uranium Company	Inactive.	-	
2	a Partnership			
3				
4				
5				
6	Edison ESI (Formerly Energy Service, Inc.)	Non-public utility engaged	100%	
7	a California Corporation	primarily in the business of		
8		furnishing energy services to		
9		commercial customers.		
10				
11				
12	Edison Material Supply LLC	Non-public utility engaged in	100%	
13	a Delaware Limited Liability Company	providing procurement, inven-		
14		tory and warehousing services		
15				
16	Mono Power Company	Inactive.	100%	
17	a California Company			
18				
19				
20				
21	SCE Capital Company	Inactive.	100%	
22	a Delaware Corporation			
23				
24	Southern States Realty (Formerly Southern	Non-public utility engaged	100%	
25	Surplus Realty Co.)	in holding real estate		
26	a California Corporation	interests.		
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions
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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	SCE Trust I	Delaware business trust	100%	
2		organized to act as a		
3		financing vehicle.		
4				
5	SCE Trust II	Delaware business trust	100%	
6		organized to act as a		
7		financing vehicle.		
8				
9	SCE Trust III	Delaware business trust	100%	
10		organized to act as a		
11		financing vehicle.		
12				
13	SCE Trust IV	Delaware business trust	100%	
14		organized to act as a		
15		financing vehicle.		
16				
17	SCE Trust V	Delaware business trust	100%	
18		organized to act as a		
19		financing vehicle.		
20				
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22				
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27				

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

Bear Creek Uranium Company

Mono Power Company, which is 100% owned by the Respondent, owns a 50% partnership interest in the Bear Creek Uranium Company; the remaining interest is owned by Anadarko Petroleum.

Schedule Page: 103 Line No.: 6 Column: a

Edison ESI dissolved 9/14/2015.

Schedule Page: 103 Line No.: 12 Column: d

Respondent is the only member of Edison Material Supply LLC.

Schedule Page: 103 Line No.: 21 Column: a

SCE Capital Company dissolved 6/19/2014.

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

Respondent owns 100% of Common Stock as of 04/24/2012.

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

Respondent owns 100% of Common Stock as of 01/29/2013.

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

Respondent owns 100% of Common Stock as of 03/06/2014.

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

Respondent owns 100% of Common Stock as of 8/24/2015.

Schedule Page: 103.1 Line No.: 17 Column: d

Respondent owns 100% of Common Stock as of 3/08/2016.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	President	Pedro J. Pizzaro	1,229,515
2			
3	Senior Vice President & Chief Financial Officer	Maria Rigatti	572,134
4			
5	Senior Vice President	Peter T. Dietrich	859,890
6			
7	Senior Vice President	Stuart R. Hemphill	570,012
8			
9	Senior Vice President & General Counsel	Russell C. Swartz	607,025
10			
11			
12	Pursuant to Item 402 of Regulation S-K, the		
13	informaton provided above was reported as "Salary,"		
14	"Bonus," "Non-Equity Incentive Plan Compensation"		
15	and "All Other Compensation" in the Summary		
16	Compensation Table of the Company's Proxy		
17	Statement filed with the Securities and Exchange		
18	Commission ("Proxy Statement"). For additional		
19	information required by Regulation S-K, Item 402, please		
20	see the Company's Proxy Statement. Officers included		
21	above are the executive officers that are the company's		
22	"Named Executive Officers" for purposes of the company's		
23	2016 Proxy Statement that fall within the term		
24	"executive officer" above.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Jagjeet S. Bindra	2244 Walnut Grove Avenue
2		Rosemead, California 91770
3		
4		
5	Vanessa C.L. Chang	2244 Walnut Grove Avenue
6		Rosemead, California 91770
7		
8		
9	Theodore F. Craver, Jr.	2244 Walnut Grove Avenue
10		Rosemead, California 91770
11		
12		
13	Bradford M. Freeman (1)	2244 Walnut Grove Avenue
14		Rosemead, California 91770
15		
16		
17	Luis G. Nogales (1)	2244 Walnut Grove Avenue
18		Rosemead, California 91770
19		
20		
21	Pedro J. Pizarro	2244 Walnut Grove Avenue
22	President	Rosemead, California 91770
23		
24		
25	Richard T. Schlosberg, III	2244 Walnut Grove Avenue
26		Rosemead, California 91770
27		
28		
29	Linda G. Stuntz	2244 Walnut Grove Avenue
30		Rosemead, California 91770
31		
32	William P. Sullivan (2)	2244 Walnut Grove Avenue
33		Rosemead, California 91770
34		
35		
36	Thomas C. Sutton (1)	2244 Walnut Grove Avenue
37		Rosemead, California 91770
38		
39		
40	Ellen O. Tauscher	2244 Walnut Grove Avenue
41		Rosemead, California 91770
42		
43		
44	Peter J. Taylor	2244 Walnut Grove Avenue
45		Rosemead, California 91770
46		
47		
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Brett White	2244 Walnut Grove Avenue
2		Rosemead, California 91770
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7	Please note: The respondent does not have a Board	
8	Executive Committee.	
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11	(1) Messrs. Freeman, Nogales and Sutton retired from	
12	The Board of Directors on April 23, 2015.	
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14	(2) Mr. Sullivan was elected to The Board of Directors	
15	on April 23, 2015.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff, Volume No. 6	ER97-2355, ER03-338, ER06-788, ER15-259 (TRBAA)
2	FERC Electric Tariff, Volume No. 6	ER01-315, ER03-142, ER04-890, ER04-1209, ER05-763,
3	FERC Electric Tariff, Volume No. 6	ER01-832, ER03-338, ER05-506, ER11-3248, ER13-1174
4	FERC Electric Tariff, Volume No. 6	ER11-3697, ER13-1190, ER13-1253, ER14-2788
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Schedule Page: 106   Line No.: 2   Column: b

FERC Electric Tariff, Volume No. 6: ER15-216 (RSBAA)

Schedule Page: 106   Line No.: 3   Column: b

FERC Electric Tariff, Volume No. 6: ER14-1604, ER15-1399 (TACBAA)

Schedule Page: 106   Line No.: 4   Column: b

FERC Electric Tariff, Volume No. 6: ER15-1449 (Base TRR)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20141031-5091	10/31/2014	ER15-259	2015 TRBAA UPDATE	FERC Electric Tariff Vol. No. 6
2	20141029-5076	10/29/2014	ER15-216	2015 RSBAA UPDATE	FERC Electric Tariff Vol. No. 6
3	20140328-5002	03/28/2014	ER14-1604	2014 TACBAA UPDATE	FERC Electric Tariff Vol. No. 6
4	20150330-5394	03/30/2015	ER15-1399	2015 TACBAA UPDATE	FERC Electric Tariff Vol. No. 6
5	20140905-5075	09/05/2014	ER14-2788	PBOPS-TRANSMISSION FORMULA	FERC Electric Tariff Vol. No. 6
6	20141125-5208	11/25/2014	ER11-3697	2015 TO9 ANNUAL	FERC Electric Tariff Vol. No. 6
7	20150403-5136	04/03/2015	ER15-1449	Formula Rate Revision - Unfunded	FERC Electric Tariff Vol. No. 6
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) X An Original (2) _ A Resubmission	04/14/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 1061 Line No.: 3 Column: a

Accession No. 20140328-5002 and 5003

Schedule Page: 1061 Line No.: 5 Column: d

PBOPS - Transmission Formula Rate

Schedule Page: 1061 Line No.: 6 Column: d

TO9 Annual Update

Schedule Page: 1061 Line No.: 7 Column: d

Unfunded Reserves - Transmission Formula Rate

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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		NONE.		
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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.

Question 1. Franchises

No significant changes

Question 2. Acquisition of ownership in other companies

Not applicable

Question 3. Purchase or sale of an operation unit or system

Not applicable

Question 4. Important Leaseholds

None. For power purchase agreements, please refer to Notes to Financial Statements Commitments and Contingencies section at page 123.4.

Question 5. Important extension or reduction of transmission or distribution system

There were no major/significant extensions or reduction of SCE service territory during the period.

Question 6. Obligations

SCE's obligations as of December 31, 2015 are summarized below.

-Long-Term Debt:

During the first quarter of 2015, SCE issued $550 million of 1.845% amortizing first and refunding mortgage bonds due in 2022, $325 million of 2.4% first and refunding mortgage bonds due in 2022, and $425 million of 3.6% first and refunding mortgage bonds due in 2045. The proceeds from these bonds were used to repay outstanding debt and for general corporate purposes. The $550 million amortizing first and refunding mortgage bonds and the $325 million of first and refunding mortgage bonds have been designated as a financing of the San Onofre regulatory asset.

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	INTEREST RATE	MATURITY DATE	AUTHORIZING CPUC DECISION
Series 2015A	1/16/15	$550	1.845%	2/1/22	No. 10-08-002 dated Aug. 13, 2010 and No. 14-03-005 dated March 18, 2014
Series 2015B	1/16/15	$325	2.400%	2/1/22	No. 14-03-005 March 18, 2014
Series 2015C	1/16/15	$425	3.600%	2/1/45	No. 05-05-008 dated Aug. 25, 2005 and No. 14-03-005 dated March 18, 2014

During the second quarter of 2015, SCE reissued $56 million of 1.875% pollution-control bonds due in 2029 and $75 million of 1.875% pollution –control bonds due in 2031. The proceeds were used to repay commercial paper borrowings and for general corporate purposes.

SERIES NAME	ISSUE DATE	REMARKETING DATE	AMOUNT (MILLIONS)	INTEREST RATE	MATURITY DATE	AUTHORIZING CPUC DECISION
Clark County, Nevada Pollution Control Refunding Revenue Bonds 2010 Series	12/16/2010	4/1/2015	$75.00	1.875%	6/01/2031	No. 05-08-008 dated Aug. 25, 2005
City of Farmington, New Mexico Pollution Control Refunding Revenue Bonds 2011 Series	5/19/2011	4/1/2015	$55.54	1.875%	4/01/2029	No. 05-08-008 dated Aug. 25, 2005

-Short-Term Obligations:

The SCE short term debt in the fourth quarter 2015 consisted of commercial paper that matures on January 4, 2016. At December 31, 2015, the principal balance (account 2662015) outstanding was $49.0 million and the unamortized discount (account 2662020) was $2,095.82. The weighted average rate was 0.51% on the $49.0 million outstanding as of December 31, 2015.

-Preferred Security Issuances:

Shares of Series J preference stock, issued in 2015, may be redeemed at par, in whole, but not in part, at any time prior to September 15, 2025, if certain changes in tax or investment company laws occur. After September 15, 2025, SCE may redeem the Series J shares, at par, in whole or in part. For shares of Series J preference stock, distributions will accrue and be payable at a floating rate from and including September 15, 2025. Shares of Series J preference stock were issued to SCE Trust IV, special purpose entity formed to issue trust securities. The proceeds from the sale of the shares of Series J were used to redeem $325 million of the Company's Series A preference stock. Preference shares are not subject to mandatory redemption.

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	DIVIDEND RATE	AUTHORIZING CPUC DECISION
Series J Preference Stock (Cumulative, $2,500 Liquidation Value)	08/24/15	$325	5.375%	No. 10-08-002 dated Aug. 12, 2010 and No. 14-03-005 dated March 18, 2014

-Indemnities:

SCE has various financial and performance guarantees and indemnity agreements which are issued in the normal course of business.

SCE has provided indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and indemnities for specified environmental liabilities and income taxes with respect to assets sold. SCE's obligations under these agreements may or may not be limited in terms of time and/or amount, and SCE may have recourse against third parties in some instances. SCE has not recorded a liability related to these indemnities. The overall maximum amount of the obligations under these indemnifications cannot be reasonably estimated.

SCE has indemnified the City of Redlands, California in connection with Mountainview's California Energy Commission permit for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this indemnity.

Question 7. Changes in articles of incorporation or amendments to charter

SCE filed a Certificate of Determination of Preferences of the Series J Preference Stock, effective August 19, 2015, in connection with the creation of a new series of preference stock.

SCE filed a Certificate of Determination of Preferences of the Series K Preference Stock, effective March 3, 2016, in connection with the creation of a new series of preference stock.

Question 8. Wage Scale Changes

The following wage scale changes have occurred during 2015 (January 1, 2015 to December 31, 2015):

- General increases for IBEW employees was 2.75%, effective January 1, 2015
- General increases for UWUA employees was 2.75%, effective January 1, 2015
- Annual merit increase budget for non-represented and non-executive employees was 2.65%, effective February 23, 2015

Question 9. Materially important legal matters.

None.

Question 10. Material transactions involving officers, directors, or security holders with a material interest in the transaction.

Director Linda Stuntz is an equity partner at the law firm of Stuntz, Davis & Staffier, P.C., which paid the Company approximately $210,448 in 2015 to sublease office space in Washington, D.C.

Except for those transactions disclosed in the Notes to Financials appearing on pages 122-123 of this filing, transactions between the respondent and its parent holding company and other affiliated entities are not understood to be subject to reporting in this item.

Question 11. (Reserved)

Question 12.

Not applicable

Question 13. Changes in a) officers and directors, b) majority security holders and c) voting powers of the respondent

a) Changes in officers and directors of the respondent.

Changes in directors of the respondent since April 13, 2015, the date "as of" which this information was reported in the 2014 FERC Form 1, are reflected below.

Director Name	Date First Elected	Effective Date	End Date (if applicable)
Bradford M. Freeman	5/14/2002	5/14/2002	4/23/2015
Luis G. Nogales	4/15/1993	4/15/1993	4/23/2015
William P. Sullivan	4/23/2015	4/23/2015	N/A
Thomas C. Sutton	4/20/1995	4/20/1995	4/23/2015

Changes in officers of the respondent since April 13, 2015, the date "as of" which this information was reported in the 2014 FERC Form 1, are reflected below.

Officer Name	Title	Date First Elected	Effective Date	End Date (if applicable)
Enrique "Henry" Martinez	Vice President	09/06/2012	09/06/2012	08/01/2015
Philip Herrington	Vice President	06/17/2015	08/03/2015	N/A
Kevin R. Cini	Vice President	02/22/2007	03/01/2007	11/06/2015
Todd L. Inlander	Senior Vice President and Chief Information Officer	02/25/2016	02/25/2016	N/A
Steven D. Powell	Vice President	02/25/2016	02/25/2016	N/A
Jeffrey L. Barnett	Vice President	06/18/2014	06/18/2014	03/15/2016

b) Changes in majority security holders.

None.

c) Changes in voting powers of the respondent.

SCE issued 130,004 shares of Series J Preference Stock on August 24, 2015. The voting rights for such stock are as follows:

The Series J Shares shall have no voting rights except as set forth below or as otherwise provided by California law:

(a) So long as any Series J Shares are outstanding, the consent of the Holders of at least a majority of the Series J Shares at the time outstanding, voting as a single class, or voting as a single class together with the holders of any other series of Preference Stock (i) upon which like voting or consent rights have been conferred and (ii) which are similarly affected by the matter to be voted upon, given in person or by proxy, either in writing or by vote at any meeting called for the purpose, shall be necessary for effecting or validating any one or more of the following:

(i) any amendment of the Corporation's Restated Articles of Incorporation which would adversely affect the rights, preferences, privileges or restrictions of the Series J Shares; or

(ii) the authorization or creation, or the increase in the authorized amount, of any stock of any class or any security convertible into stock of any class, ranking senior to the Series J Shares with respect to payment of dividends and distribution of assets upon liquidation, dissolution or winding up of the Corporation.

provided, however, that no such consent of the Holders of Series J Shares shall be required if, at or prior to the time when such amendment is to take effect or when the authorization, creation or increase in the authorized amount of any such senior stock or convertible security is to be made, as the case may be, provision is to be made for the redemption of all Series J Shares at the time outstanding.

On matters requiring their consent, the Holders will be entitled to one vote per Share.

SCE issued 120,004 shares of Series K Preference Stock on March 8, 2016. The voting rights for such stock are as follows:

The Series K Shares shall have no voting rights except as set forth in this Section 3 or as otherwise provided by California law:

(a) So long as any Series K Shares are outstanding, the consent of the Holders of at least a majority of the Series K Shares at the time outstanding, voting as a single class, or voting as a single class together with the holders of any other series of Preference Stock (i) upon which like voting or consent rights have been conferred and (ii) which are similarly affected by the matter to be voted upon, given in person or by proxy, either in writing or by vote at any meeting called for the purpose, shall be necessary for effecting or validating any one or more of the following:

(i) any amendment of the Corporation's Restated Articles of Incorporation which would adversely affect the rights, preferences, privileges or restrictions of the Series K Shares; or

(ii) the authorization or creation, or the increase in the authorized amount, of any stock of any class or any security convertible into stock of any class, ranking senior to the Series K Shares with respect to payment of dividends and distribution of assets upon liquidation, dissolution or winding up of the Corporation.

provided, however, that no such consent of the Holders of Series K Shares shall be required if, at or prior to the time when such amendment is to take effect or when the authorization, creation or increase in the authorized amount of any such senior stock or convertible security is to be made, as the case may be, provision is to be made for the redemption of all Series K Shares at the time outstanding.

On matters requiring their consent, the Holders will be entitled to one vote per Share.

Question 14. Cash Management Program

There was no cash management program.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	41,658,218,003	39,038,060,665
3	Construction Work in Progress (107)	200-201	3,218,015,337	3,338,863,344
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		44,876,233,340	42,376,924,009
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	12,841,098,825	12,474,003,654
6	Net Utility Plant (Enter Total of line 4 less 5)		32,035,134,515	29,902,920,355
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	57,994,661	53,747,473
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		138,903,872	191,001,509
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	65,580,263	114,144,642
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		131,318,270	130,604,340
14	Net Utility Plant (Enter Total of lines 6 and 13)		32,166,452,785	30,033,524,695
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		153,584,350	143,548,825
19	(Less) Accum. Prov. for Depr. and Amort. (122)		80,504,208	74,705,379
20	Investments in Associated Companies (123)		40,000	30,000
21	Investment in Subsidiary Companies (123.1)	224-225	722,549	8,666,351
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	6,405,922	7,093,551
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)		4,531,367,759	4,991,961,082
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		83,985,171	218,805,861
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,695,601,543	5,295,400,291
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		16,999,698	24,012,613
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		122,100	124,800
38	Temporary Cash Investments (136)		23,710,663	21,305,537
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		646,798,783	648,452,810
41	Other Accounts Receivable (143)		261,329,311	277,374,054
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		61,772,305	67,823,852
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		1,595,096	1,067,636
45	Fuel Stock (151)	227	4,378,586	6,768,745
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	251,648,702	268,228,990
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	13,548,725	26,892,012

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		6,405,922	7,093,551
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		91,007,488	88,925,394
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		25,023	19,763
60	Rents Receivable (172)		3,739,264	3,773,849
61	Accrued Utility Revenues (173)		564,148,998	631,706,020
62	Miscellaneous Current and Accrued Assets (174)		16,035,041	44,567,750
63	Derivative Instrument Assets (175)		162,641,443	320,923,117
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		83,985,171	218,805,861
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,905,565,523	2,070,419,826
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		84,227,978	75,224,486
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	99,511,638	173,743,597
72	Other Regulatory Assets (182.3)	232	7,931,674,751	9,176,328,731
73	Prelim. Survey and Investigation Charges (Electric) (183)		165,493	138,506
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)		154,890	144,495
77	Temporary Facilities (185)		192,558	327,940
78	Miscellaneous Deferred Debits (186)	233	118,350,676	123,453,674
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)		201,260,974	201,215,715
82	Accumulated Deferred Income Taxes (190)	234	1,181,571,512	1,866,874,677
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		9,617,110,470	11,617,451,821
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		48,384,730,321	49,016,796,633

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	2,168,054,319	2,168,054,319
3	Preferred Stock Issued (204)	250-251	2,070,044,950	2,070,034,950
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		923,708	923,708
7	Other Paid-In Capital (208-211)	253	702,407,126	666,772,625
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	583	583
10	(Less) Capital Stock Expense (214)	254b	51,413,648	49,403,455
11	Retained Earnings (215, 215.1, 216)	118-119	8,806,143,025	8,448,198,516
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,026,801	5,697,001
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)	-22,132,856	-28,166,048
16	Total Proprietary Capital (lines 2 through 15)		13,671,999,240	13,282,111,033
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	10,375,114,286	9,814,400,000
19	(Less) Reaquired Bonds (222)	256-257	30,000,000	160,540,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	306,682,234	306,739,959
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		36,460,491	36,995,246
24	Total Long-Term Debt (lines 18 through 23)		10,615,336,029	9,923,604,713
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		48,882,986	195,560,185
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		205,916,363	228,785,013
29	Accumulated Provision for Pensions and Benefits (228.3)		1,288,471,486	1,678,754,015
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		1,099,594,606	1,052,070,629
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,762,243,898	2,819,427,330
35	Total Other Noncurrent Liabilities (lines 26 through 34)		5,405,109,339	5,974,597,172
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		48,997,904	666,975,002
38	Accounts Payable (232)		1,231,481,228	1,467,964,518
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		4,369,552	497,724
41	Customer Deposits (235)		243,432,117	221,876,849
42	Taxes Accrued (236)	262-263	91,727,467	250,456,644
43	Interest Accrued (237)		170,675,155	170,252,065
44	Dividends Declared (238)		13,364,834	163,305,782
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	end of 2015/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)		24,409,315	27,145,586
48	Miscellaneous Current and Accrued Liabilities (242)		564,099,504	747,807,271
49	Obligations Under Capital Leases-Current (243)		2,964,311	7,298,885
50	Derivative Instrument Liabilities (244)		1,317,113,676	1,247,931,408
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		1,099,594,606	1,052,070,629
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)		2,613,040,457	3,919,441,105
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		228,239,976	186,272,963
57	Accumulated Deferred Investment Tax Credits (255)	266-267	93,335,951	102,269,658
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	1,396,212,581	1,395,356,873
60	Other Regulatory Liabilities (254)	278	4,103,124,744	3,743,734,429
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)		9,464,558,141	9,089,861,319
64	Accum. Deferred Income Taxes-Other (283)		793,773,863	1,399,547,368
65	Total Deferred Credits (lines 56 through 64)		16,079,245,256	15,917,042,610
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		48,384,730,321	49,016,796,633

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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	12,986,461,164	14,200,417,112		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	7,021,516,203	9,700,439,922		
5	Maintenance Expenses (402)	320-323	394,588,414	414,621,773		
6	Depreciation Expense (403)	336-337	1,429,475,185	1,352,969,480		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	479,673,333	363,651,635		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	124,619	140,196		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		47,322	5,712,300		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,289,414,817	-599,982,423		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	327,120,173	316,609,986		
15	Income Taxes - Federal (409.1)	262-263	10,628,615	-27,968,121		
16	- Other (409.1)	262-263	119,715,770	106,089,339		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	3,719,855,148	446,730,864		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	3,231,071,411	23,095,161		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,352,711	-5,336,960		
20	(Less) Gains from Disp. of Utility Plant (411.6)			121,309		
21	Losses from Disp. of Utility Plant (411.7)			144,217,869		
22	(Less) Gains from Disposition of Allowances (411.8)		59	-3,716		
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)		11,555,735,418	12,194,683,106		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,430,725,746	2,005,734,006		

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
12,981,700,156	14,195,272,632	2,129,932	2,452,471	2,631,076	2,692,009	2
						3
7,018,791,177	9,697,402,117	1,437,025	1,681,702	1,288,001	1,356,103	4
389,670,753	409,065,143	610,026	284,272	4,307,635	5,272,358	5
1,428,490,091	1,343,181,002	147,938	122,657	837,156	9,665,821	6
						7
479,673,333	363,651,635					8
124,619	140,196					9
47,322	5,712,300					10
						11
1,289,414,817	-599,982,423					12
						13
326,874,857	316,367,591	38,130	30,304	207,186	212,091	14
12,757,218	-26,382,629	-171,224	109,675	-1,957,379	-1,695,167	15
120,217,740	106,452,339	-34	31,264	-501,936	-394,264	16
3,718,421,936	450,249,247	338,188	17,612	1,095,024	-3,535,995	17
3,230,020,633	23,095,161	177,530		873,248		18
-5,352,711	-5,336,960					19
	121,309					20
	144,217,869					21
59	-3,716					22
						23
						24
11,549,110,460	12,181,524,673	2,222,519	2,277,486	4,402,439	10,880,947	25
1,432,589,696	2,013,747,959	-92,587	174,985	-1,771,363	-8,188,938	26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,430,725,746	2,005,734,006		
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)		69,236,085	67,677,885		
34	(Less) Expenses of Nonutility Operations (417.1)		38,636,238	42,904,011		
35	Nonoperating Rental Income (418)		674,667	341,075		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	151,081	-3,754		
37	Interest and Dividend Income (419)		4,237,081	7,959,337		
38	Allowance for Other Funds Used During Construction (419.1)		86,954,871	65,285,406		
39	Miscellaneous Nonoperating Income (421)		17,194,264	15,804,088		
40	Gain on Disposition of Property (421.1)		35,999	3,446,189		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		139,847,810	117,606,215		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		684,472	106,588		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		22,933,497	41,743,507		
46	Life Insurance (426.2)		-22,848,502	-26,116,643		
47	Penalties (426.3)		17,080,670	10,985,944		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		11,177,024	11,671,721		
49	Other Deductions (426.5)		7,781,197	6,846,787		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		36,808,358	45,237,904		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	2,904,272	2,857,460		
53	Income Taxes-Federal (409.2)	262-263	-103,271,181	-14,704,197		
54	Income Taxes-Other (409.2)	262-263	-22,275,478	-2,754,036		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	16,681,376	885,498		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,596,799	1,244,668		
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)		-108,557,810	-14,959,943		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		211,597,262	87,328,254		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		472,179,700	473,381,575		
63	Amort. of Debt Disc. and Expense (428)		27,997,794	31,446,113		
64	Amortization of Loss on Reaquired Debt (428.1)					
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)		62,124,903	48,901,644		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		31,034,535	25,352,129		
70	Net Interest Charges (Total of lines 62 thru 69)		531,267,862	528,377,203		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,111,055,146	1,564,685,057		
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)		1,111,055,146	1,564,685,057		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		8,271,982,359	7,415,668,479
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11	Stock based compensation		-32,631,771	(67,653,622)
12	Capital stock expense write off		-4,409,386	
13	SCE Capital close out		-120,000	(2,619,024)
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-37,161,157	(70,272,646)
16	Balance Transferred from Income (Account 433 less Account 418.1)		1,110,904,065	1,564,688,811
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of Retained Earnings	215.1	-9,037,426	(754,178)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-9,037,426	(754,178)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred and preference stock dividends (see footnote)		-112,634,891	(112,295,310)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-112,634,891	(112,295,310)
30	Dividends Declared-Common Stock (Account 438)			
31	Common stock dividends		-611,158,391	(525,052,797)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-611,158,391	(525,052,797)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		7,994,883	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		8,620,889,442	8,271,982,359
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)		185,253,583	176,216,157
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		185,253,583	176,216,157
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		8,806,143,025	8,448,198,516
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		5,697,001	3,081,731
50	Equity in Earnings for Year (Credit) (Account 418.1)		151,081	(3,754)
51	(Less) Dividends Received (Debit)		7,994,883	
52	Other		120,000	2,619,024
53	Balance-End of Year (Total lines 49 thru 52)		-2,026,801	5,697,001

Schedule Page: 118 Line No.: 24 Column: a

NOTES TO STATEMENT OF RETAINED EARNINGS FOR
THE YEAR TO DATE DECEMBER 31, 2015

		Dividend
Preferred Stock -		
4.08%	Series	$ 663,000
4.24%	Series	1,272,000
4.32%	Series	1,785,704
4.78%	Series	1,549,641
Preference Stock -		
*	Series A	8,270,711
6.500%	Series D	8,125,000
6.250%	Series E	21,875,000
5.625%	Series F	26,718,751
5.100%	Series G	20,400,000
5.750%	Series H	15,812,498
5.375%	Series J	6,162,586
Total Dividends		$ 112,634,891

* Variable rate

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)	1,111,055,146	1,564,685,057
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,908,335,365	1,712,685,133
5	Amortization of Nuc. Fuel, Loss on Reacq. Debt, Disc. of L/T Debt	69,712,333	71,996,496
6			
7			
8	Deferred Income Taxes (Net)	502,700,831	401,716,241
9	Investment Tax Credit Adjustment (Net)	-5,352,711	-5,336,960
10	Net (Increase) Decrease in Receivables	24,815,306	66,159,033
11	Net (Increase) Decrease in Inventory	18,970,446	-19,303,550
12	Net (Increase) Decrease in Allowances Inventory	12,655,659	13,262,817
13	Net Increase (Decrease) in Payables and Accrued Expenses	-98,378,188	-36,356,930
14	Net (Increase) Decrease in Other Regulatory Assets	737,328,619	60,054,024
15	Net Increase (Decrease) in Other Regulatory Liabilities	991,969,013	-416,765,953
16	(Less) Allowance for Other Funds Used During Construction	86,954,871	65,285,406
17	(Less) Undistributed Earnings from Subsidiary Companies	151,081	-3,754
18	Other (provide details in footnote):		
19	Prepaid and accrued taxes	-136,489,942	156,899,927
20	Nuclear decommissioning trusts	-427,604,575	38,799,963
21	Other - Net	432,243	116,341,948
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	4,623,043,593	3,659,555,594
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-3,688,808,300	-3,420,081,687
27	Gross Additions to Nuclear Fuel	-42,428,469	-44,994,692
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-11,793,704	-5,511,896
30	(Less) Allowance for Other Funds Used During Construction	-86,954,871	-65,285,406
31	Other (provide details in footnote):		
32	Cost of removal, salvage value and others	-553,921,521	-452,088,433
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-4,209,997,123	-3,857,391,302
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	233,002	3,735,622
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies	7,929,260	
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
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Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: Proceeds from Sale of Nuclear Decommissioning Trust Investments	3,506,139,999	2,617,216,349
54	Purchases of Nuclear Decommissioning Trust Investments	-3,131,634,481	-2,661,767,546
55	Customer Advances for Construction and Other Investments	11,396,206	44,824,517
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-3,815,933,137	-3,853,382,360
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,428,885,250	499,872,000
62	Preferred Stock		
63	Common Stock		
64	Other: Refundable customer advances for construction	45,294,545	63,582,798
65	Preference Stock Issued	325,000,000	275,000,000
66	Net Increase in Short-Term Debt (c)		490,089,227
67	Other (provide details in footnote):		
68	Tax Benefit Related to Stock-based Compensation	22,668,074	19,591,400
69	Proceeds from Stock-based Compensation	45,257,585	124,772,901
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,867,105,454	1,472,908,326
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-761,316,684	-606,776,320
74	Preferred Stock	-325,000,000	
75	Common Stock		
76	Other: Long-term debt and preference stock issuance cost	-21,996,515	-8,308,036
77	Shares purchased for stock-based compensation	-77,843,474	-188,418,848
78	Net Decrease in Short-Term Debt (c)	-618,935,494	
79	Dividends on Preference Stock	-110,252,699	-105,404,063
80	Dividends on Preferred Stock	-5,270,345	-5,270,345
81	Dividends on Common Stock	-758,211,188	-378,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-811,720,945	180,730,714
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-4,610,489	-13,096,052
87			
88	Cash and Cash Equivalents at Beginning of Period	45,442,950	58,539,002
89			
90	Cash and Cash Equivalents at End of period	40,832,461	45,442,950

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.

GLOSSARY

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

AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company, operator of Four Corners
ARO(s)	asset retirement obligation(s)
Bcf	billion cubic feet
Bonus depreciation	Current federal tax deduction of a percentage of the qualifying property placed in service during periods permitted under tax laws
CAA	Clean Air Act
CAISO	California Independent System Operator
CARB	California Air Resources Board
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DOE	U.S. Department of Energy
ERRA	energy resource recovery account
FERC	Federal Energy Regulatory Commission
Four Corners	coal fueled electric generating facility located in Farmington, New Mexico in which SCE held a 48% ownership interest
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GRC	general rate case
GWh	gigawatt-hours
IRS	Internal Revenue Service
Joint Proxy Statement	SCE's definitive Proxy Statement to be filed with the SEC in connection with SCE's Annual Shareholders' Meeting to be held on April 28, 2016
MHI	Mitsubishi Heavy Industries, Inc. and related companies
Moody's	Moody's Investors Service
MW	megawatts
MWh	megawatt-hours
NAAQS	national ambient air quality standards
NEIL	Nuclear Electric Insurance Limited
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
ORA	CPUC's Office of Ratepayers Advocates
OII	Order Instituting Investigation
Palo Verde	nuclear electric generating facility located near Phoenix, Arizona in which SCE holds a 15.8% ownership interest
PBOP(s)	postretirement benefits other than pension(s)
PG&E	Pacific Gas & Electric Company

QF(s)	qualifying facility(ies)
ROE	return on common equity
S&P	Standard & Poor's Ratings Services
San Onofre	retired nuclear generating facility located in south San Clemente, California in which SCE holds a 78.21% ownership interest
San Onofre OII Settlement Agreement	Settlement Agreement by and among The Utility Reform Network, the CPUC's Office of Ratepayer Advocates, SDG&E, the Coalition of California Utility Employees, and Friends of the Earth, dated November 20, 2014
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or CPSD
TURN	The Utility Reform Network
US EPA	U.S. Environmental Protection Agency
VIE(s)	variable interest entity(ies)

Item 1. Notes to Financial Statements

General Note

SCE is an investor-owned public utility primarily engaged in the business of supplying and delivering electricity to an approximately 50,000 square mile area of southern California. SCE's consolidated financial statements include the accounts of SCE and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the consolidated financial statements.

These financial statements are prepared in accordance with the requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases which is a comprehensive basis of accounting other than generally accepted accounting principles. These notes include specific information required by the FERC. See the Company's Annual Report to Shareholders as of and for the year-ended, December 31, 2015 for financial statements and complete footnotes prepared in accordance with accounting principles generally accepted in the United States.

SCE follows accounting principles for rate-regulated enterprises which are required for entities whose rates are set by regulators at levels intended to recover the estimated costs of providing services, plus a return on net investment, or rate base. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow a cost that would otherwise be charged as an expense by a unregulated entity to be capitalized as a regulatory asset if it is probable that such cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. SCE's management assess at the end of each reporting period whether regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific or a similar incurred cost to SCE or other rate-regulated entities in California, and other factors that would indicate that the regulator will treat an incurred cost as allowable for rate-making purposes.

Financial statements prepared in conformity with FERC as set forth in its applicable Uniform System of Accounts and published accounting releases require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingency assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Actual results could differ from those estimates.

Certain prior year amounts have been reclassified for consistency with the current period presentation. The proceeds from the sales and purchases of nuclear decommissioning trust investments in the consolidated statement of cash flows of SCE net quick turnaround investment activity in the amount of $13.7 billion, $7.5 billion, and $4.4 billion for the years ended December 31, 2015, 2014 and 2013, respectively.

The following are material differences between FERC reporting standards and GAAP:

- Equity Investment Differences

SCE accounts for its investments in majority-owned subsidiaries using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries which is required by GAAP. In general, the accounting for investments in majority-owned subsidiaries using the equity method rather than the method in accordance with GAAP has no effect on net income or retained earnings. Due to the nature of the business, SCE continues to consolidate Edison Material and Supplies.

- Asset Retirement Obligation

The accumulated net removal costs for SCE's regulated plant assets that do not meet the definition of an ARO or conditional ARO under authoritative accounting guidance are classified as regulatory liabilities under GAAP and as accumulated depreciation under FERC.

- Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans

For FERC reporting purposes, the asset for an overfunded postretirement defined benefit plan is classified on the FERC financial statements as special funds, a noncurrent asset. For GAAP reporting purposes, this asset is classified as a miscellaneous deferred debit, which is also a noncurrent asset.

- Other Differences

The FERC required current maturities of long-term debt to be included as part of long-term debt, while GAAP requires such maturities to be classified as a current liability. Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent. Retained earnings are presented differently under the Uniform System of Accounts for FERC purposes than it is for GAAP purposes. Additionally, the FERC requires only current year presentation of statements of cash flows and retained earnings while GAAP requires a comparative presentation.

Subsequent Events

Subsequent events were evaluated through the date the FERC Form 1 report was filed.

Energy Storage Assets

Energy storage assets totaled $11 million at December 31, 2015, all of which was recorded in plant account 395 – Laboratory Equipment. These energy storage assets are in the testing phase and have not and will not be deployed as production, transmission or distribution assets to serve our customers.

There is no purchased power or operation and maintenance expense for the year ended December, 31, 2015 related to energy storage.

Commitments

Third-Party Power Purchase Agreements

SCE entered into various agreements, which were approved by the CPUC and met critical contract provisions (including completion of major milestones for construction), to purchase power and electric capacity, including:

- *Renewable Energy Contracts* – California law requires retail sellers of electricity to comply with a RPS by delivering renewable energy, primarily through power purchase contracts. Renewable energy contracts generally contain escalation clauses requiring increases in payments. As of December 31, 2015, SCE had 93 renewable energy contracts which expire at various dates through 2038.

- *Qualifying Facility Power Purchase Agreements* – Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities are required, with exceptions, to purchase energy and capacity from independent power producers that are qualifying co-generation facilities and qualifying small power production facilities ("QFs"). As of December 31, 2015, SCE had 71 QF contracts.

- *Other Power Purchase Agreements* – SCE has entered into agreements with third parties, including 6 combined heat and power contracts, 9 tolling arrangements and 11 resource adequacy contracts which expire at various dates through 2025.

At December 31, 2015, the undiscounted future minimum expected payments for the SCE power purchase agreements that have been approved by the CPUC and have completed major milestones for construction were as follows:

(in millions)	Renewable Energy Contracts	QF Power Purchase Agreements	Other Purchase Agreements
2016	$ 1,234	$ 223	$ 741
2017	1,417	189	758
2018	1,472	149	589
2019	1,562	87	503
2020	1,605	39	459
Thereafter	21,439	69	1,022
Total future commitments	$ 28,729	$ 756	$ 4,072

The table above includes contractual obligations for power procurement contracts that met the critical contract provisions as of December 31, 2015. Additionally, as of December 31, 2015, SCE has signed contracts that have not met the critical contract provisions that would increase contractual obligations by $29 million in 2016, $166 million in 2017, $257 million in 2018, $352 million in 2019, $747 million in 2020 and $16.4 billion thereafter, if all principal provisions are completed.

Many of the power purchase agreements that SCE entered into with independent power producers are treated as operating and capital leases. The following table shows the future minimum lease payments due under the contracts that are treated as operating and capital leases (these amounts are also included in the table above). Due to the inherent uncertainty associated with the reliability of the fuel source, expected purchases from most renewable energy contracts do not meet the definition of a minimum lease payment and have been excluded from the operating and capital lease table below but remain in the table above. The future minimum lease payments for capital leases are discounted to their present value in the table below using SCE's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	Operating Leases	Capital Leases[1]
2016	$ 374	$ 1
2017	354	1
2018	250	2
2019	186	2
2020	174	2
Thereafter	1,745	10
Total future commitments	$ 3,083	$ 18
Amount representing executory costs		(7)
Amount representing interest		(3)
Net commitments		$ 8

1 Excludes $44 million of obligation related to an SCE power contract that was classified as a capital lease in 2014. During 2015, the contract was amended, which resulted in a reduction in the lease obligations and asset by $147 million in 2015. The amended contract contained terms that no longer met the lease criteria.

Operating lease expense for power purchase agreements was $1.7 billion in 2015, $1.7 billion in 2014 and $1.5 billion in 2013 (including contingent rents of $1.1 billion in 2015, $944 million in 2014 and $843 million in 2013). The timing of SCE's recognition of the lease expense conforms to ratemaking treatment for SCE's recovery of the cost of electricity and is included in purchased power.

At December 31, 2015 and 2014, SCE's net capital leases were $8 million and $203 million, including accumulated amortization of $2 million and $46 million, respectively.

Other Lease Commitments

The following summarizes the estimated minimum future commitments for SCE's noncancelable other operating leases (excluding SCE's power purchase agreements discussed above):

(in millions)	Operating Leases – Other
2016	$ 68
2017	52
2018	44
2019	35
2020	27
Thereafter	271
Total future commitments	$ 497

Operating lease expense for other leases (primarily related to vehicles, office space, nuclear fuel storage space and other equipment) were $80 million in 2015, $96 million in 2014 and $78 million in 2013. SCE has also entered into a number of agreements to lease property and equipment in the normal course of business. Minimum lease payments under operating leases are levelized (total minimum lease payments divided by the number of years of the lease) and recorded as rent expense over the terms of the leases. Lease payments in excess of the minimum are recorded as rent expense in the year incurred. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage over base year, or the customer price index. Lease payments in excess of the minimum are recorded as rent expense in the year incurred.

Nuclear Decommissioning

Decommissioning costs, which are recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. Amortization of the ARO asset (included within the unamortized nuclear investment) and accretion of the ARO liability are deferred as increases to the ARO regulatory liability account, resulting in no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The cost of removal amounts, in excess of amounts collected for assets not legally required to be removed, are classified as regulatory liabilities.

Changes in the estimated costs, timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE currently estimates that it will spend approximately $7.2 billion through

2075 to decommission its nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.4% to 7.3% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts. SCE estimates annual after-tax earnings on the decommissioning funds of 3.3% to 4.1%. If the assumed return on trust assets is not earned or costs escalate at higher rates, it is probable that additional funds needed for decommissioning will be recoverable through rates in the future.

Decommissioning expense amounts collected in rates were $5 million in 2014 and $22 million in 2013. Total expenditures for the decommissioning of San Onofre Unit 1 were $484 million (SCE's share) from the beginning of the project in 1998 through December 31, 2015.

Due to regulatory recovery of SCE's nuclear decommissioning expense, prudently incurred costs for nuclear decommissioning activities do not affect SCE's earnings. SCE's nuclear decommissioning costs are subject to CPUC review through the tri-annual regulatory proceeding. SCE's nuclear decommissioning trust investments primarily consist of debt and equity investments that are classified as available-for-sale. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on electric utility revenue. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust assets and the related regulatory asset or liability and have no impact on electric utility revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment on the last day of each month. If the fair value on the last day of two consecutive months is less than the cost for that security, SCE recognizes a loss for the other-than-temporary impairment. If the fair value is greater or less than the cost for that security at the time of sale, SCE recognizes a related realized gain or loss, respectively.

Future decommissioning costs of removal of SCE's nuclear assets are expected to be funded from independent decommissioning trusts.

The following table sets forth amortized cost and fair value of the trust investments:

(in millions)	Longest Maturity Date	Amortized Cost December 31, 2015	Amortized Cost December 31, 2014	Fair Value December 31, 2015	Fair Value December 31, 2014
Stocks	—	$ 304	$ 524	$ 1,460	$ 2,031
Municipal bonds	2054	691	681	840	822
U.S. government and agency securities	2046	1,070	777	1,128	836
Corporate bonds	2057	708	346	755	395
Short-term investments and receivables/payables[1]	One-year	144	692	148	715
Total		$ 2,917	$ 3,020	$ 4,331	$ 4,799

1 Short-term investments include $81 million and $164 million of repurchase agreements payable by financial institutions which earn interest, are fully secured by U.S. Treasury securities and mature by January 5, 2016 and January 7, 2015 as of December 31, 2015 and 2014, respectively.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Unrealized holding gains, net of losses, were $1.4 billion and $1.8 billion at December 31, 2015 and 2014, respectively.

The following table sets forth a summary of changes in the fair value of the trusts:

	Years ended December 31,		
(in millions)	2015	2014	2013
Balance at beginning of period	$ 4,799	$ 4,494	$ 4,048
Gross realized gains	326	197	300
Gross realized losses	(26)	(5)	(32)
Unrealized (losses) gains	(364)	75	160
Other-than-temporary impairments	(29)	(14)	(47)
Interest, dividends and other	115	118	113
Contributions	54	5	22
Income taxes	(64)	(62)	(66)
Decommissioning disbursements	(471)	(4)	—
Administrative expenses and other	(9)	(5)	(4)
Balance at end of period	$ 4,331	$ 4,799	$ 4,494

Trust assets are used to pay income taxes as the Trust files separate income taxes returns from SCE. Deferred income taxes related to unrealized gains at December 31, 2015 were $360 million. Accordingly, the fair value of Trust assets available to pay future decommissioning costs, net of deferred income taxes, totaled $4.0 billion at December 31, 2015. Due to regulatory mechanisms, changes in assets of the trusts from income items have no impact on operating revenue or earnings.

For the year ended December 31, 2015, the trust reimbursed SCE for $471 million of 2013, 2014 and 2015 Units 2 and 3 decommissioning costs. Under the San Onofre OII Settlement Agreement, recoveries from the nuclear decommissioning trusts of 2013 and 2014 decommissioning costs were refunded to customers primarily through ERRA.

Other Commitments

The following summarizes the estimated minimum future commitments for SCE's other commitments:

(in millions)	2016	2017	2018	2019	2020	Thereafter	Total
Other contractual obligations	$ 181	$ 140	$ 101	$ 56	$ 59	$ 547	$ 1,084

Costs incurred for other commitments were $182 million in 2015, $90 million in 2014 and $153 million in 2013. SCE has fuel supply contracts for Palo Verde which require payment only if the fuel is made available for purchase. SCE also has commitments related to maintaining reliability and expanding SCE's transmission and distribution system.

The table above excludes other contractual obligations that have not met the critical contract provisions. As of December 31, 2015, SCE has signed capacity reduction contracts that have not met critical contract provisions and are, therefore, not included in the table above. These contracts would increase the contractual obligations by $10 million in 2017, $98 million in 2018, $82 million in 2019, $79 million in 2020 and $483 million thereafter, if all principal provisions are completed.

Indemnities

SCE has various financial and performance guarantees and indemnity agreements which are issued in the normal course of business.

SCE has provided indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and indemnities for specified environmental liabilities and income taxes with respect to assets sold. SCE's obligations under these agreements may or may not be limited in terms of time and/or amount, and in some instances SCE may have recourse against third parties. SCE has not recorded a liability related to these indemnities. The overall maximum amount of the obligations under these indemnifications cannot be reasonably estimated.

SCE has indemnified the City of Redlands, California in connection with Mountainview's California Energy Commission permit for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this indemnity.

Compensation and Benefit Plans

Employee Savings Plan

The 401(k) defined contribution savings plan is designed to supplement employees' retirement income. The following employer contributions were made for continuing operations:

(in millions)	Years ended December 31,
2015	$ 72
2014	70
2013	76

Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

Noncontributory defined benefit pension plans (some with cash balance features) cover most employees meeting minimum service requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking. The expected contribution (all by the employer) for SCE is approximately $94 million for the year ending December 31, 2016. Annual contributions made by SCE to most of SCE's pension plans are anticipated to be recovered through CPUC-approved regulatory mechanisms. Annual contributions to these plans are expected to be, at a minimum, equal to the related annual expense.

The funded position of pension is sensitive to changes in market conditions. Changes in overall interest rate levels significantly affect the company's liabilities, while assets held in the various trusts established to fund pension are affected by movements in the equity and bond markets. Due to SCE's regulatory recovery treatment, a regulatory asset has been recorded equal to the unfunded status. Information on pension plan assets and benefit obligations is shown below.

(in millions)	Years ended December 31, 2015	2014
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 3,999	$ 3,721
Service cost	133	124
Interest cost	150	159
Actuarial (gain) loss	(143)	386
Curtailment gain	—	—
Benefits paid	(261)	(391)
Other	—	—
Projected benefit obligation at end of year	$ 3,878	$ 3,999
Change in plan assets		
Fair value of plan assets at beginning of year	$ 3,217	$ 3,236
Actual return on plan assets	27	240
Employer contributions	97	132
Benefits paid	(261)	(391)
Fair value of plan assets at end of year	$ 3,080	$ 3,217
Funded status at end of year	$ (798)	$ (782)
Amounts recognized in the consolidated balance sheets consist of[1]:		
Current liabilities	$ (4)	$ (5)
Long-term liabilities	(794)	(777)
	$ (798)	$ (782)
Amounts recognized in accumulated other comprehensive loss consist of:		
Net loss[1]	$ 27	$ 31
Amounts recognized as a regulatory asset:		
Prior service cost	$ 15	$ 20
Net loss	660	640
	$ 675	$ 660
Total not yet recognized as expense	$ 702	$ 691
Accumulated benefit obligation at end of year	$ 3,744	$ 3,881
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 3,878	$ 3,999
Accumulated benefit obligation	3,744	3,881
Fair value of plan assets	3,080	3,217
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	4.18%	3.85%
Rate of compensation increase	4.00%	4.00%

1 The SCE liability excludes a long-term payable due to Edison International Parent of $123 million and $121 million at December 31, 2015 and 2014, respectively, related to certain SCE postretirement benefit obligations transferred to Edison International Parent. SCE's accumulated other comprehensive loss of $27 million and $31 million at December 31, 2015 and 2014, respectively, excludes net loss of $18 million and $22 million related to these benefits.

In 2015 and 2014, SCE adopted new mortality tables that the Society of Actuaries released in October each year that reflect changes in life expectancy. At December 31, 2015 and 2014, this adoption resulted in a change in the pension plans' projected benefit obligation of $(31) million and $199 million, respectively, for SCE.

Pension expense components are:

	Years ended December 31,		
(in millions)	2015	2014	2013
Service cost	$ 139	$ 128	$ 159
Interest cost	155	164	167
Expected return on plan assets	(217)	(213)	(222)
Settlement costs	—	42	85
Curtailment gain	—	—	—
Amortization of prior service cost	5	5	5
Amortization of net loss[1]	35	7	35
Expense under accounting standards	117	133	229
Regulatory adjustment (deferred)	(6)	8	(53)
Total expense recognized	$ 111	$ 141	$ 176

1 Includes the amount of net loss reclassified from other comprehensive loss. The amount reclassified for SCE was $8 million and 4 million for the year ended December 31, 2015 and December 31, 2014, respectively.

Under GAAP, a settlement is recorded when lump-sum payments exceed estimated annual service and interest costs. Lump-sum payments to employees retiring in 2014 and 2013 from the SCE Retirement Plan (primarily due to workforce reductions described below) exceeded the estimated service and interest costs for those years. A settlement requires re-measurement of both the plan pension obligations and plan assets as of the date of the settlement. Re-measurement assumption changes result in actuarial gains and losses which are combined with previous unrecognized gains and losses. After re-measurement, GAAP requires an acceleration of a portion of unrecognized net losses attributable to such lump-sum payments as additional pension expense as reflected in the above table. The additional pension expense related to SCE did not impact net income as such amounts are probable of recovery through future rates.

The SCE Retirement Plan experienced total actuarial losses of $374 million, including $357 million for SCE during 2014. The actuarial losses in 2014 were primarily due to a decrease in the discount rate (from 4.75% at December 31, 2013 to 4.00% as of August 31, 2014 and 3.85% as of December 31, 2014) due to lower interest rates.

Other changes in pension plan assets and benefit obligations recognized in other comprehensive loss are:

(in millions)	Years ended December 31, 2015	2014	2013
Net loss (gain)	$ (9)	$ 37	$ (24)
Amortization of net loss and other	(9)	(4)	(7)
Total recognized in other comprehensive loss	$ (18)	$ 33	$ (31)
Total recognized in expense and other comprehensive loss	$ 93	$ 174	$ 145

In accordance with authoritative guidance on rate-regulated enterprises, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of SCE's postretirement benefit plans that are recoverable in utility rates. The estimated pension amounts that will be amortized to expense in 2016 are as follows:

(in millions)	
Unrecognized net loss to be amortized[1]	$ 32
Unrecognized prior service cost to be amortized	4

1 The amount of net loss expected to be reclassified from other comprehensive loss for SCE is $6 million.

SCE used the following weighted-average assumptions to determine pension expense:

	Years ended December 31, 2015	2014	2013
Discount rate	3.85%	4.50%	4.13%
Rate of compensation increase	4.00%	4.00%	4.50%
Expected long-term return on plan assets	7.00%	7.00%	7.00%

The following benefit payments, which reflect expected future service, are expected to be paid:

(in millions)		Years ended December 31,
2016	$	265
2017		270
2018		280
2019		286
2020		290
2021 – 2025		1,447

Postretirement Benefits Other Than Pensions ("PBOP(s)")

Most employees retiring at or after age 55 with at least 10 years of service may be eligible for postretirement medical, dental, vision and life insurance benefits. Eligibility for a company contribution toward the cost of these benefits in retirement depends on a number of factors, including the employee's years of service, hire date, and retirement date. Under the terms of the Edison International Health and Welfare Plan ("PBOP Plan") each participating employer (Edison International or its participating subsidiaries) is responsible for the costs and expenses of all PBOP benefits with respect to its employees and former employees. A participating employer may terminate the PBOP benefits with respect to its employees and former employees, as may SCE (as Plan sponsor), and, accordingly, the participants' PBOP benefits are not vested benefits.

The expected contributions (substantially all of which are expected to be made by SCE) for PBOP benefits are $33 million for the year ended December 31, 2016. Annual contributions related to SCE employees made to SCE plans are anticipated to be recovered through CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to the total annual expense for these plans.

SCE has established three voluntary employee beneficiary associations trusts ("VEBA Trusts") that can only be used to pay for retiree health care benefits of SCE. Once funded into the VEBA Trusts, neither SCE nor Edison International can subsequently terminate benefits and recover remaining amounts in the VEBA Trusts. Participants of the PBOP Plan do not have a beneficial interest in the VEBA Trusts. The VEBA Trust assets are sensitive to changes in market conditions. Changes in overall interest rate levels significantly affect the company's liabilities, while assets held in the various trusts established to fund other postretirement benefits are affected by movements in the equity and bond markets. Due to SCE's regulatory recovery treatment, the unfunded status is offset by a regulatory asset.

Information on PBOP Plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31, 2015	2014
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,775	$ 2,211
Service cost	46	40
Interest cost	102	117
Special termination benefits	(2)	3
Actuarial (gain) loss	(500)	582
Plan participants' contributions	20	19
Benefits paid	(100)	(197)
Benefit obligation at end of year	$ 2,341	$ 2,775
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,086	$ 2,065
Actual return on assets	6	180
Employer contributions	24	19
Plan participants' contributions	20	19
Benefits paid	(100)	(197)
Fair value of plan assets at end of year	$ 2,036	$ 2,086
Funded status at end of year	$ (305)	$ (689)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$ (15)	$ (15)
Long-term liabilities	(290)	(674)
	$ (305)	$ (689)
Amounts recognized in accumulated other comprehensive loss consist of:		
Net loss	$ —	$ —
Amounts recognized as a regulatory (liability) asset:		
Prior service credit	$ (9)	$ (19)
Net loss	183	577
	$ 174	$ 558
Total not yet recognized as expense	$ 174	$ 558
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	4.55%	4.16%
Assumed health care cost trend rates:		
Rate assumed for following year	7.50%	7.75%
Ultimate rate	5.00%	5.00%
Year ultimate rate reached	2022	2021

During 2015, the PBOP plan had actuarial gains of $500 million primarily related to $300 million in experience gains, $140 million of income from an increase in the discount rate (from 4.16% at December 31, 2014 to 4.55% as of December 31, 2015) due to higher interest rates, and the adoption of new mortality tables, as discussed below.

In 2015 and 2014, SCE adopted new mortality tables that the Society of Actuaries released in October each year that reflect changes in life expectancy. At December 31, 2015 and 2014, this adoption resulted in a change in the PBOP plans' accumulated postretirement benefit obligation of $(61) million and $307 million, respectively, for SCE.

PBOP expense components are:

	Years ended December 31,		
(in millions)	2015	2014	2013
Service cost	$ 46	$ 40	$ 48
Interest cost	102	117	97
Expected return on plan assets	(116)	(108)	(114)
Special termination benefits[1]	1	3	11
Amortization of prior service credit	(12)	(35)	(35)
Amortization of net loss	2	5	24
Total expense	$ 23	$ 22	$ 31

1 Due to the reduction in workforce, SCE has incurred costs for extended retiree health care coverage.

In accordance with authoritative guidance on rate-regulated enterprises, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of SCE's postretirement benefit plans that are recoverable in utility rates. The estimated PBOP amounts that will be amortized to expense in 2016 are as follows:

(in millions)	
Unrecognized prior service credit to be amortized	$ (3)

SCE used the following weighted-average assumptions to determine PBOP expense:

	Years ended December 31,		
	2015	2014	2013
Discount rate	4.16%	5.00%	4.25%
Expected long-term return on plan assets	5.50%	5.50%	6.70%
Assumed health care cost trend rates:			
Current year	7.75%	7.75%	8.50%
Ultimate rate	5.00%	5.00%	5.00%
Year ultimate rate reached	2021	2020	2020

A one-percentage-point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on accumulated benefit obligation as of December 31, 2015	$ 250	$ (205)
Effect on annual aggregate service and interest costs	12	(9)

The following benefit payments are expected to be paid:

(in millions)	Years ended December 31,
2016	$ 101
2017	106
2018	110
2019	114
2020	118
2021 – 2025	646

Plan Assets

Description of Pension and Postretirement Benefits Other than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. Target allocations for 2015 pension plan assets were 29% for U.S. equities, 17% for non-U.S. equities, 35% for fixed income, 15% for opportunistic and/or alternative investments and 4% for other investments. Target allocations for 2015 PBOP plan assets (except for Represented VEBA which is 85% for fixed income, 10% for opportunistic/private equities, and 5% global equities) are 41% for U.S. equities, 17% for non-U.S. equities, 34% for fixed income, 7% for opportunistic and/or alternative investments, and 1% for other investments. SCE employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is managed through diversification among multiple asset classes, managers, styles and securities. Plan asset classes and individual manager performances are measured against targets. SCE also monitors the stability of its investment managers' organizations.

Allowable investment types include:

- United States Equities: Common and preferred stocks of large, medium, and small companies which are predominantly United States-based.
- Non-United States Equities: Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.
- Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities including municipal bonds, mortgage backed securities and corporate debt obligations. A portion of the fixed income positions may be held in debt securities that are below investment grade.

Opportunistic, Alternative and Other Investments:

- Opportunistic: Investments in short to intermediate term market opportunities. Investments may have fixed income and/or equity characteristics and may be either liquid or illiquid.
- Alternative: Limited partnerships that invest in non-publicly traded entities.
- Other: Investments diversified among multiple asset classes such as global equity, fixed income currency and commodities markets. Investments are made in liquid instruments within and across markets. The investment returns are expected to approximate the plans' expected investment returns.

Asset class portfolio weights are permitted to range within plus or minus 3%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to reallocate portfolio cash positions. Where authorized, a few of the plans' investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets

The overall expected long-term rate of return on assets assumption is based on the long-term target asset allocation for plan assets and capital markets return forecasts for asset classes employed. A portion of the PBOP trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

SCE's capital markets return forecast methodologies primarily use a combination of historical market data, current market conditions, proprietary forecasting expertise, complex models to develop asset class return forecasts and a building block approach. The forecasts are developed using variables such as real risk-free interest, inflation, and asset class specific risk premiums. For equities, the risk premium is based on an assumed average equity risk premium of 5% over cash. The forecasted return on private equity and opportunistic investments are estimated at a 2% premium above public equity, reflecting a premium for higher volatility and lower liquidity. For fixed income, the risk premium is based off of a comprehensive modeling of credit spreads.

Fair Value of Plan Assets

The PBOP Plan and the Southern California Edison Company Retirement Plan Trust (Master Trust) assets include investments in equity securities, U.S. treasury securities, other fixed-income securities, common/collective funds, mutual funds, other investment entities, foreign exchange and interest rate contracts, and partnership/joint ventures. Equity securities, U.S. treasury securities, mutual and money market funds are classified as Level 1 as fair value is determined by observable, unadjusted quoted market prices in active or highly liquid and transparent markets. Common/collective funds are valued at the net asset value ("NAV") of shares held. Although common/collective funds are determined by observable prices, they are classified as Level 2 because they trade in markets that are less active and transparent. The fair value of the underlying investments in equity mutual funds and equity common/collective funds are based upon stock-exchange prices. The fair value of the underlying investments in fixed-income common/collective funds, fixed-income mutual funds and other fixed income securities including municipal bonds are based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information. Foreign exchange and interest rate contracts are classified as Level 2 because the values are based on observable prices but are not traded on an exchange. Futures contracts trade on an exchange and therefore are classified as Level 1. The partnerships classified as Level 2 can be readily redeemed at NAV and the underlying investments are liquid, publicly traded fixed-income securities which have observable prices. The remaining partnerships/joint ventures are classified as Level 3 because fair value is determined primarily based upon management estimates of future cash flows. Other investment entities are valued similarly to common/collective funds and are therefore classified as Level 2. The Level 1 registered investment companies are either mutual or money market funds. The remaining funds in this category are readily redeemable at NAV and classified as Level 2.

SCE reviews the process/procedures of both the pricing services and the trustee to gain an understanding of the inputs/assumptions and valuation techniques used to price each asset type/class. The trustee and SCE's validation procedures for pension and PBOP equity and fixed income securities are the same as the nuclear decommissioning trusts. The values of Level 1 mutual and money market funds are publicly quoted. The trustees obtain the values of common/collective and other investment funds from the fund managers. The values of partnerships are based on partnership valuation statements updated for cash flows. SCE's investment managers corroborate the trustee fair values.

Pension Plan

The following table sets forth the Master Trust investments for SCE that were accounted for at fair value as of December 31, 2015 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
U.S. government and agency securities[1]	$ 127	$ 298	$ —	$ 425
Corporate stocks[2]	720	16	—	736
Corporate bonds[3]	—	755	—	755
Common/collective funds[4]	—	640	—	640
Partnerships/joint ventures[5]	—	111	214	325
Other investment entities[6]	—	263	—	263
Registered investment companies[7]	117	4	—	121
Interest-bearing cash	6	—	—	6
Other	1	96	—	97
Total	$ 971	$ 2,183	$ 214	$ 3,368
Receivables and payables, net				(70)
Net plan assets available for benefits				$ 3,298
SCE's share of net plan assets				$ 3,080

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2014 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
U.S. government and agency securities[1]	$ 140	$ 329	$ —	$ 469
Corporate stocks[2]	716	14	—	730
Corporate bonds[3]	—	801	—	801
Common/collective funds[4]	—	524	—	524
Partnerships/joint ventures[5]	—	110	289	399
Other investment entities[6]	—	278	—	278
Registered investment companies[7]	113	30	—	143
Interest-bearing cash	10	—	—	10
Other	5	100	—	105
Total	$ 984	$ 2,186	$ 289	$ 3,459
Receivables and payables, net				(5)
Net plan assets available for benefits				$ 3,454
SCE's share of net plan assets				$ 3,217

1 Level 1 U.S. government and agency securities are U.S. treasury bonds and notes. Level 2 primarily relates to the Federal National Mortgage Association and the Federal Home Loan Mortgage Corporation.

2 Corporate stocks are diversified. For both 2015 and 2014, performance for actively managed separate accounts is primarily benchmarked against the Russell Indexes (59%) and Morgan Stanley Capital International (MSCI) index (41%).

3 Corporate bonds are diversified. At December 31, 2015 and 2014, respectively, this category includes $123 million and $102 million for collateralized mortgage obligations and other asset backed securities of which $25 million and $15 million are below investment grade.

4 At December 31, 2015 and 2014, respectively, the common/collective assets were invested in equity index funds that seek to track performance of the Standard and Poor's (S&P 500) Index (46% and 32%), Russell 1000 indexes (14% and 18%) and the MSCI Europe, Australasia and Far East (EAFE) Index (16% and 20%). A non-index U.S. equity fund representing 22% and 27% of this category for 2015 and 2014, respectively, is actively managed.

5 Partnerships/joint venture Level 2 investments consist primarily of a partnership which invests in publicly traded fixed income securities. At December 31, 2015 and 2014, respectively, 22% and 55% of the Level 3 partnerships are invested in (1) asset backed securities, including distressed mortgages and (2) commercial and residential loans and debt and equity of banks. At December 31, 2015 and 2014, respectively, 78% and 45% of the Level 3 partnerships are invested in private equity funds with investment strategies that include branded consumer products, clean technology and California geographic focus companies.

6 Other investment entities were primarily invested in (1) emerging market equity securities, (2) a hedge fund that invests through liquid instruments in a global diversified portfolio of equity, fixed income, interest rate, foreign currency and commodities markets, and (3) domestic mortgage backed securities.

7 Level 1 of registered investment companies primarily consisted of a global equity mutual fund which seeks to outperform the MSCI World Total Return Index. Level 2 primarily consisted of a short-term bond fund.

At December 31, 2015 and 2014, approximately 63% and 65%, respectively, of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

The following table sets forth a summary of changes in the fair value of SCE's Level 3 investments:

(in millions)	2015	2014
Fair value, net at beginning of period	$ 289	$ 390
Actual return on plan assets:		
Relating to assets still held at end of period	47	114
Relating to assets sold during the period	(17)	(44)
Purchases	38	13
Dispositions	(143)	(184)
Transfers in and/or out of Level 3	—	—
Fair value, net at end of period	$ 214	$ 289

Postretirement Benefits Other than Pensions

The following table sets forth the VEBA Trust assets for SCE that were accounted for at fair value as of December 31, 2015 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Common/collective funds[1]	$ —	$ 424	$ —	$ 424
Corporate stocks[2]	222	—	—	222
Corporate notes and bonds[3]	—	867	—	867
Partnerships[4]	—	20	73	93
U.S. government and agency securities[5]	200	42	—	242
Registered investment companies[6]	60	3	—	63
Interest bearing cash	31	—	—	31
Other[7]	5	113	—	118
Total	$ 518	$ 1,469	$ 73	$ 2,060
Receivables and payables, net				(24)
Combined net plan assets available for benefits				$ 2,036

The following table sets forth the VEBA Trust assets for SCE that were accounted for at fair value as of December 31, 2014 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Common/collective funds[1]	$ —	$ 431	$ —	$ 431
Corporate stocks[2]	250	—	—	250
Corporate notes and bonds[3]	—	883	—	883
Partnerships[4]	—	19	105	124
U.S. government and agency securities[5]	207	36	—	243
Registered investment companies[6]	64	5	—	69
Interest bearing cash	29	—	—	29
Other[7]	5	125	—	130
Total	$ 555	$ 1,499	$ 105	$ 2,159
Receivables and payables, net				(73)
Combined net plan assets available for benefits				$ 2,086

1 At both December 31, 2015 and 2014, 38% of the common/collective assets are invested in a large cap index fund which seeks to track performance of the Russell 1000 index. 41% of the assets in this category are in index funds which seek to track performance in the MSCI All Country World Index Investable Market Index and MSCI Europe, Australasia and Far East (EAFE) Index. 17% in a non-index U.S. equity fund which is actively managed.

2 Corporate stock performance for actively managed separate accounts is primarily benchmarked against the Russell Indexes (47%) and the MSCI All Country World Index (53%) for both 2015 and 2014.

3 Corporate notes and bonds are diversified and include approximately $27 million and $31 million for commercial collateralized mortgage obligations and other asset backed securities at December 31, 2015 and 2014, respectively.

4 At December 31, 2015 and 2014, respectively, 29% and 50% of the Level 3 partnerships category is invested in (1) asset backed securities including distressed mortgages, (2) distressed companies and (3) commercial and residential loans and debt and equity of banks. At December 31, 2015 and 2014, respectively, 71% and 50% of the Level 3 partnerships are invested in private equity and venture capital funds. Investment strategies for these funds include branded consumer products, clean and information technology and healthcare.

5 Level 1 U.S. government and agency securities are U.S. treasury bonds and notes. Level 2 primarily relates to the Federal Home Loan Mortgage Corporation and the Federal National Mortgage Association.

6 Level 1 registered investment companies consist of a money market fund.

7 Other includes $97 million and $111 million of municipal securities at December 31, 2015 and 2014, respectively.

At both December 31, 2015 and 2014, approximately 71% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

The following table sets forth a summary of changes in the fair value of PBOP Level 3 investments:

(in millions)	2015	2014
Fair value, net at beginning of period	$ 105	$ 164
Actual return on plan assets		
Relating to assets still held at end of period	(6)	18
Relating to assets sold during the period	15	(1)
Purchases	7	9
Dispositions	(47)	(85)
Transfers in and/or out of Level 3	—	—
Fair value, net at end of period	$ 74	$ 105

Stock-Based Compensation

Stock options, performance shares, deferred stock units and restricted stock units have been granted under Edison International's long-term incentive compensation programs. Generally, Edison International does not issue new common stock for settlement of equity awards. Rather, a third party is used to purchase shares from the market and delivery for settlement of option exercises, performance shares and restricted stock units. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Deferred stock units granted to management are settled in cash and represent a liability. Restricted stock units are settled in common stock; however, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

Stock-based compensation expense is recognized on a straight-line basis over the requisite service period. For awards granted to retirement-eligible participants stock compensation expenses are recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement.

Tax benefits related to stock-based compensation are recognized as a reduction to deferred taxes until the related tax deductions reduce current income taxes. When such event occurs, the tax benefits are then recognized through additional paid in capital. SCE allocates the tax benefits based on the provisions in the tax laws that identify the sequence in which the amounts are utilized for tax purposes.

Edison International maintains a shareholder approved incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. The maximum number of shares of Edison International's common stock authorized to be issued or transferred pursuant to awards under the 2007 Performance Incentive Plan, as amended, is 49.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued ("carry-over shares"). As of December 31, 2015, Edison International had approximately 18 million shares remaining for future issuance under its stock-based compensation plans.

The following table summarizes total expense and tax benefits (expense) associated with stock based compensation:

	Years ended December 31,		
(in millions)	2015	2014	2013
Stock-based compensation expense:			
Stock options	$ 8	$ 8	$ 11
Performance shares	4	8	2
Restricted stock units	4	4	4
Other	—	—	—
Total stock-based compensation expense	$ 16	$ 20	$ 17
Income tax benefits related to stock compensation expense	$ 7	$ 8	$ 7
Excess tax benefits	23	20	2

Stock Options

Under various plans, Edison International has granted stock options at exercise prices equal to the closing price at the grant date. Prior to 2007, average of the high and low price was used. Edison International may grant stock options and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants. Additionally, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

The fair value for each option granted was determined as of the grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table:

	Years ended December 31,		
	2015	2014	2013
Expected terms (in years)	5.9	6.0	6.2
Risk-free interest rate	1.6% – 2.1%	1.8% – 2.1%	1.0% – 2.1%
Expected dividend yield	2.6% – 3.2%	2.4% – 2.7%	2.7% – 3.1%
Weighted-average expected dividend yield	2.6%	2.7%	2.8%
Expected volatility	16.4% – 17.0%	17.8% – 19.1%	17.7% – 18.6%
Weighted-average volatility	16.5%	18.9%	17.7%

The expected term represents the period of time for which the options are expected to be outstanding and is primarily based on historical exercise and post-vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a zero coupon U.S. Treasury STRIPS (separate trading of registered interest and principal of securities) whose maturity equals the option's expected term on the measurement date. Expected volatility is based on the historical volatility of Edison International's common stock for the length of the option's expected term for 2015. The volatility period used was 71 months, 72 months and 74 months at December 31, 2015, 2014 and 2013, respectively.

The following is a summary of the status of stock options:

		Weighted-Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2014	6,002,160	$ 43.82		
Granted	1,099,566	63.52		
Expired	—	—		
Forfeited	(109,719)	53.45		
Exercised	(1,085,438)	41.74		
Transfers, net	(66,512)	40.88		
Outstanding at December 31, 2015	5,840,057	47.77	6.20	
Vested and expected to vest at December 31, 2015	5,771,064	47.62	6.17	$ 72
Exercisable at December 31, 2015	3,751,272	42.17	4.99	$ 64

At December 31, 2015, total unrecognized compensation cost related to stock options and the weighted-average period the cost is expected to be recognized are as follows:

(in millions)	
Unrecognized compensation cost, net of expected forfeitures	$ 9
Weighted-average period (in years)	2.4

Supplemental Data on Stock Options

	Years ended December 31,		
(in millions, except per award amounts)	2015	2014	2013
Stock options:			
Weighted average grant date fair value per option granted	$ 7.53	$ 7.34	$ 5.38
Fair value of options vested	11	9	10
Cash used to purchase shares to settle options	69	181	130
Cash from participants to exercise stock options	45	125	92
Value of options exercised	24	56	38
Tax benefits from options exercised	10	23	15

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2015, 2014 and 2013 and vest at the end of a three year period for each grant. The vesting of the grants is dependent upon market and financial performance conditions and service conditions as defined in the grants for each of the years. The number of performance shares earned from each year's grants could range from zero to twice the target number (plus additional units credited as dividend equivalents). Performance shares awarded in 2014 and 2013 that are earned are settled half in cash and half in common stock, while performance shares awarded in 2015 that are earned are settled solely in cash. The portion of performance shares that can be settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value, which for each share is determined as the closing price of Edison International common stock on the grant date; however, with respect to the portion of the performance shares payable in common stock that is subject to the financial performance condition defined in the grants, the number of performance shares expected to be earned is subject to revision and updated at each reporting period, with a related adjustment of compensation expense. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined (subject to the adjustments discussed above), except for awards granted to retirement-eligible participants.

The fair value of market condition performance shares is determined using a Monte Carlo simulation valuation model.

The following is a summary of the status of nonvested performance shares:

	Equity Awards		Liability Awards	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Fair Value
Nonvested at December 31, 2014	71,797	$ 56.06	71,520	$ 92.33
Granted	—	—	59,213	
Forfeited	(1,717)	56.89	(2,867)	
Vested[1]	(36,891)	50.82	(36,748)	
Affiliate transfers, net	(726)	54.81	(725)	
Nonvested at December 31, 2015	32,463	62.01	90,393	68.64

[1] Relates to performance shares that will be paid in 2016 as performance targets were met at December 31, 2015.

Restricted Stock Units

Restricted stock units were awarded to SCE's executives in March 2015, 2014 and 2013 and vest and become payable on January 2, 2018, January 3, 2017 and December 31, 2015, respectively. Each restricted stock unit awarded includes a dividend equivalent feature and is a contractual right to receive one share of Edison International common stock, if vesting requirements are satisfied. The vesting of Edison International's restricted stock units is dependent upon continuous service through the end of the vesting period.

The following is a summary of the status of nonvested restricted stock units:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2014	231,364	$ 48.26
Granted	65,237	63.52
Forfeited	(5,108)	54.04
Vested	(155,046)	45.98
Affiliate transfers, net	(2,072)	45.35
Nonvested at December 31, 2015	134,375	58.13

The fair value for each restricted stock unit awarded is determined as the closing price of Edison International common stock on the grant date.

Workforce Reductions

SCE continues to focus on productivity improvements to mitigate rate pressure from its capital program, optimize its cost structure and improve operational efficiency, which is expected to result in further workforce reductions through 2016. During the year ended December 31, 2015, SCE increased the estimated impact for approved workforce reductions. The following table provides a summary of changes in the accrued severance liability associated with these reductions:

(in millions)		
Balance at January 1, 2015	$	35
Additions		26
Payments		(39)
Balance at December 31, 2015	$	22

Deferred Financing Costs

Debt premium, discount and issuance expenses incurred in connection with obtaining financing are deferred and amortized on a straight-line basis. Under CPUC ratemaking procedures, SCE's debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. SCE had unamortized losses on reacquired debt of $201 million for both December 31, 2015 and 2014. SCE had unamortized debt issuance costs of $84 million at December 31, 2015, and $75 million at December 31, 2014. Amortization of deferred financing costs charged to interest expense was $28 million, $32 million and $32 million for 2015, 2014 and 2013, respectively.

Derivative Instruments

SCE records derivative instruments on its consolidated balance sheets as either assets or liabilities measured at fair value unless otherwise exempted from derivative treatment as normal purchases or sales. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Realized gains and losses from SCE's derivative instruments are expected to be recovered from or refunded to customers through regulatory mechanisms and, therefore, SCE's fair value changes have no impact on purchased-power expense or earnings. SCE does not use hedge accounting for derivative transactions due to regulatory accounting treatment.

Where SCE's derivative instruments are subject to a master netting agreement and certain criteria are met, SCE presents its derivative assets and liabilities on a net basis on its consolidated balance sheets. In addition, derivative positions are offset against margin and cash collateral deposits. The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows.

Derivative financial instruments are used to manage exposure to commodity price risk. These risks are managed in part by entering into forward commodity transactions, including options, swaps and futures. To mitigate credit risk from counterparties in the event of nonperformance, master netting agreements are used whenever possible and counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Commodity Price Risk

Commodity price risk represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's electricity price exposure arises from energy purchased from and sold to wholesale markets as a result of differences between SCE's load requirements and the amount of energy delivered from its generating facilities and power purchase agreements. SCE's natural gas price exposure arises from natural gas purchased for the Mountainview power plant and peaker plants, QF contracts where pricing is based on a monthly natural gas index and power purchase agreements in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements.

Credit and Default Risk

Credit and default risk represent the potential impact that can be caused if a counterparty were to default on its contractual obligations and SCE would be exposed to spot markets for buying replacement power or selling excess power. In addition, SCE would be exposed to the risk of non-payment of accounts receivable, primarily related to the sales of excess power and realized gains on derivative instruments.

Certain power contracts contain master netting agreements or similar agreements, which generally allow counterparties subject to the agreement to setoff amounts when certain criteria are met, such as in the event of default. The objective of netting is to reduce credit exposure. Additionally, to reduce SCE's risk exposures counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Certain power contracts contain a provision that requires SCE to maintain an investment grade rating from each of the major credit rating agencies, referred to as a credit-risk-related contingent feature. If SCE's credit rating were to fall below investment grade, SCE may be required to post additional collateral to cover derivative liabilities and the related outstanding payables. The net fair value of all derivative liabilities with these credit-risk-related contingent features was $38 million and $53 million as of December 31, 2015 and 2014, respectively, for which SCE has posted no collateral and $13 million of collateral to its counterparties at December 31, 2015 and 2014, respectively. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2015, SCE would be required to post $22 million of additional collateral of which $8 million is related to outstanding payables that are net of collateral already posted.

Fair Value of Derivative Instruments

SCE presents its derivative assets and liabilities on a net basis on its consolidated balance sheets when subject to master netting agreements or similar agreements. Derivative positions are offset against margin and cash collateral deposits. In addition, SCE has provided collateral in the form of letters of credit. Collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments and other factors. The following table summarizes the gross and net fair values of SCE's commodity derivative instruments:

	December 31, 2015						
	Derivative Assets			Derivative Liabilities			Net Liability
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Commodity derivative contracts							
Gross amounts recognized	$ 81	$ 84	$ 165	$ 235	$ 1,100	$ 1,335	$ 1,170
Gross amounts offset in consolidated balance sheets	(2)	—	(2)	(2)	—	(2)	—
Cash collateral posted[1]	—	—	—	(15)	—	(15)	(15)
Net amounts presented in the consolidated balance sheets	$ 79	$ 84	$ 163	$ 218	$ 1,100	$ 1,318	$ 1,155

	December 31, 2014						
	Derivative Assets			Derivative Liabilities			Net Liability
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Commodity derivative contracts							
Gross amounts recognized	$ 104	$ 219	$ 323	$ 259	$ 1,052	$ 1,311	$ 988
Gross amounts offset in consolidated balance sheets	(2)	—	(2)	(2)	—	(2)	—
Cash collateral posted[1]	—	—	—	(61)	—	(61)	(61)
Net amounts presented in the consolidated balance sheets	$ 102	$ 219	$ 321	$ 196	$ 1,052	$ 1,248	$ 927

1 In addition, at December 31, 2015 and 2014, SCE had posted $31 million and $36 million, respectively, of collateral that is not offset against derivative liabilities.

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased power expense and expects that such gains or losses will be part of the purchase power costs recovered from customers. As a result, realized gains and losses do not affect earnings, but may temporarily affect cash flows. Due to expected future recovery from customers, unrealized gains and losses are recorded as regulatory assets and liabilities and therefore also do not affect earnings. The remaining effects of derivative activities and related regulatory offsets are recorded in cash flows from operating activities in the consolidated statements of cash flows.

The following table summarizes the components of SCE's economic hedging activity:

	Years ended December 31,		
(in millions)	2015	2014	2013
Realized losses	$ (148)	$ (57)	$ (56)
Unrealized (losses) gains	(182)	(147)	93

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for SCE hedging activities:

		Economic Hedges	
	Unit of	December 31,	
Commodity	Measure	2015	2014
Electricity options, swaps and forwards	GWh	6,221	3,618
Natural gas options, swaps and forwards	Bcf	32	83
Congestion revenue rights	GWh	109,740	122,859
Tolling arrangements	GWh	70,663	79,989

Fair Value Measurements

Recurring Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (referred to as an "exit price"). Fair value of an asset or liability considers assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk. As of December 31, 2015 and 2014, nonperformance risk was not material for SCE.

Assets and liabilities are categorized into a three-level fair value hierarchy based on valuation inputs used to determine fair value.

Level 1 – The fair value of SCE's Level 1 assets and liabilities is determined using unadjusted quoted prices in active markets that are available at the measurement date for identical assets and liabilities. This level includes exchange-traded equity securities, U.S. treasury securities, mutual funds and money market funds.

Level 2 – SCE's Level 2 assets and liabilities include fixed income securities, primarily consisting of U.S. government and agency bonds, municipal bonds and corporate bonds, and over-the-counter derivatives. The fair value of fixed income securities is determined using a market approach by obtaining quoted prices for similar assets and liabilities in active markets and inputs that are observable, either directly or indirectly, for substantially the full term of the instrument.

The fair value of SCE's over-the-counter derivative contracts is determined using an income approach. SCE uses standard pricing models to determine the net present value of estimated future cash flows. Inputs to the pricing models include forward published or posted clearing prices from exchanges (New York Mercantile Exchange and Intercontinental Exchange) for similar instruments and discount rates. A primary price source that best represents trade activity for each market is used to develop observable forward market prices in determining the fair value of these positions. Broker quotes, prices from exchanges or comparison to executed trades are used to validate and corroborate the primary price source. These price quotations reflect mid-market prices (average of bid and ask) and are obtained from sources believed to provide the most liquid market for the commodity.

Level 3 – The fair value of SCE's Level 3 assets and liabilities is determined using the income approach through various models and techniques that require significant unobservable inputs. This level includes over-the-counter options, tolling arrangements and derivative contracts that trade infrequently such as congestion revenue rights ("CRRs") and other power agreements.

Assumptions are made in order to value derivative contracts in which observable inputs are not available. Changes in fair value are based on changes to forward market prices, including extrapolation of short-term observable inputs into forecasted prices for illiquid forward periods. In circumstances where fair value cannot be verified with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. Modeling methodologies, inputs and techniques are reviewed and assessed as markets continue to develop and more pricing information becomes available and the fair value is adjusted when it is concluded that a change in inputs or techniques would result in a new valuation that better reflects the fair value of those derivative contracts.

The following table sets forth assets and liabilities of SCE that were accounted for at fair value by level within the fair value hierarchy:

	December 31, 2015				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at fair value					
Derivative contracts	$ —	$ —	$ 163	$ —	$ 163
Other	28	—	—	—	28
Nuclear decommissioning trusts:					
Stocks[2]	1,460	—	—	—	1,460
Fixed income[3]	947	1,776	—	—	2,723
Short-term investments, primarily cash equivalents	91	81	—	—	172
Subtotal of nuclear decommissioning trusts[4]	2,498	1,857	—	—	4,355
Total assets	2,526	1,857	163	—	4,546
Liabilities at fair value					
Derivative contracts	—	22	1,311	(15)	1,318
Total liabilities	—	22	1,311	(15)	1,318
Net assets (liabilities)	$ 2,526	$ 1,835	$ (1,148)	$ 15	$ 3,228

	December 31, 2014				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at fair value					
Derivative contracts	$ —	$ —	$ 321	$ —	$ 321
Other	33	—	—	—	33
Nuclear decommissioning trusts:					
Stocks[2]	2,031	—	—	—	2,031
Fixed income[3]	703	1,350	—	—	2,053
Short-term investments, primarily cash equivalents	606	166	—	—	772
Subtotal of nuclear decommissioning trusts[4]	3,340	1,516	—	—	4,856
Total assets	3,373	1,516	321	—	5,210
Liabilities at fair value					
Derivative contracts	—	86	1,223	(61)	1,248
Total liabilities	—	86	1,223	(61)	1,248
Net assets (liabilities)	$ 3,373	$ 1,430	$ (902)	$ 61	$ 3,962

1 Represents the netting of assets and liabilities under master netting agreements and cash collateral across the levels of the fair value hierarchy.

Netting among positions classified within the same level is included in that level.

2 Approximately 70% and 73% of SCE's equity investments were located in the United States at December 31, 2015 and 2014, respectively.

3 Includes corporate bonds, which were diversified and included collateralized mortgage obligations and other asset backed securities of $111 million and $49 million at December 31, 2015 and 2014, respectively.

4 Excludes net payables of $24 million and $57 million at December 31, 2015 and 2014, which consist of interest and dividend receivables as well as receivables and payables related to SCE's pending securities sales and purchases.

Fair Value of Level 3

The following table sets forth a summary of changes in SCE's fair value of Level 3 net derivative assets and liabilities:

	December 31,	
(in millions)	2015	2014
Fair value of net liabilities at beginning of period	$ (902)	$ (805)
Total realized/unrealized gains (losses):		
Included in regulatory assets and liabilities[1]	(246)	(97)
Purchases	—	27
Settlements	—	(27)
Fair value of net liabilities at end of period	$ (1,148)	$ (902)
Change during the period in unrealized gains and losses related to assets and liabilities held at the end of the period	$ (311)	$ (166)

1 Due to regulatory mechanisms, SCE's realized and unrealized gains and losses are recorded as regulatory assets and liabilities.

SCE recognizes the fair value for transfers in and transfers out of each level at the end of each reporting period. There were no significant transfers between any levels during 2015 and 2014.

Valuation Techniques Used to Determine Fair Value

The process of determining fair value is the responsibility of SCE's risk management department, which report to SCE's chief financial officer. This department obtains observable and unobservable inputs through broker quotes, exchanges and internal valuation techniques that use both standard and proprietary models to determine fair value. Each reporting period, the risk and finance departments collaborate to determine the appropriate fair value methodologies and classifications for each derivative. Inputs are validated for reasonableness by comparison against prior prices, other broker quotes and volatility fluctuation thresholds. Inputs used and valuations are reviewed period-over-period and compared with market conditions to determine reasonableness.

The following table sets forth SCE's valuation techniques and significant unobservable inputs used to determine fair value for significant Level 3 assets and liabilities:

	Fair Value (in millions)				
	Assets	Liabilities	Valuation Technique(s)	Significant Unobservable Input	Range (Weighted Average)
Congestion revenue rights					
December 31, 2015	$ 152	$ —	Market simulation model and auction prices	Load forecast	6,289 MW - 24,349 MW
				Power prices[1]	$0 - $110.44
				Gas prices[2]	$1.98 - $5.72
December 31, 2014	317	—	Market simulation model and auction prices	Load forecast	7,630 MW - 25,431 MW
				Power prices[1]	$1.65 - $109.95
				Gas prices[2]	$3.65 - $6.53
Tolling					
December 31, 2015	10	1,297	Option model	Volatility of gas prices	15% - 58% (20%)
				Volatility of power prices	26% - 38% (30%)
				Power prices	$24.15 - $46.93 ($34.80)
December 31, 2014	4	1,207	Option model	Volatility of gas prices	13% - 53% (20%)
				Volatility of power prices	25% - 42% (30%)
				Power prices	$30.60 - $61.40 ($44.60)

1 Prices are in dollars per megawatt-hour.

2 Prices are in dollars per million British thermal units.

Level 3 Fair Value Sensitivity

Congestion Revenue Rights

For CRRs, where SCE is the buyer, generally increases (decreases) in forecasted load in isolation would result in increases (decreases) to the fair value. In general, an increase (decrease) in electricity and gas prices at illiquid locations tends to result in increases (decreases) to fair value; however, changes in electricity and gas prices in opposite directions may have varying results on fair value.

Tolling Arrangements

The fair values of SCE's tolling arrangements contain intrinsic value and time value. Intrinsic value is the difference between the market price and strike price of the underlying commodity. Time value is made up of several components, including volatility, time to expiration, and interest rates. The option model for tolling arrangements reflects plant specific information such as operating and start-up costs.

For tolling arrangements where SCE is the buyer, increases in volatility of the underlying commodity prices would result in increases to fair value as it represents greater price movement risk. As power and gas prices increase, the fair value of tolling arrangements tends to increase. The valuation of tolling arrangements is also impacted by the correlation between gas and power prices. As the correlation increases, the fair value of tolling arrangements tends to decline.

Nuclear Decommissioning Trusts

SCE's nuclear decommissioning trust investments include equity securities, U.S. treasury securities and other fixed income securities. Equity and treasury securities are classified as Level 1 as fair value is determined by observable market prices in active or highly liquid and transparent markets. The remaining fixed income securities are classified as Level 2. The fair value of these financial instruments is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information.

SCE's investment policies and CPUC requirements place limitations on the types and investment grade ratings of the securities that may be held by the nuclear decommissioning trust funds. These policies restrict the trust funds from holding alternative investments and limit the trust funds' exposures to investments in highly illiquid markets. With respect to equity and fixed income securities, the trustee obtains prices from third-party pricing services which SCE is able to independently corroborate as described below. A primary price source is identified by the trustee based on asset type, class or issue for each security. The trustee monitors prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the trustee or SCE's investment managers challenge an assigned price and determine that another price source is considered to be preferable. Parameters and predetermined tolerance thresholds are established by asset class based on past experience and an understanding of valuation process techniques. The trustee "scrubs" prices against defined parameters' tolerances and performs research and resolves variances beyond the set parameters. SCE reviewed the process/procedures of both the pricing services and the trustee to gain an understanding of the inputs/assumptions and valuation techniques used to price each asset type/class and to reach a conclusion that their pricing controls are satisfactory. This consisted of SCE's review of their written detailed process/procedures and service organization control reports, as well as follow-up conversations based on our written questions. This assists SCE in determining if the valuations represent exit price fair value and that investments are appropriately classified in the fair value hierarchy. Additionally, SCE corroborates the fair values of securities by comparison to other market-based price sources obtained by SCE's investment managers. Differences outside established thresholds are followed-up with the trustee and resolved. The results of this process have demonstrated that vendor and trustee pricing controls are satisfactory. For each reporting period, SCE reviews the trustee determined fair value hierarchy and overrides the trustee level classification when appropriate.

Fair Value of Debt Recorded at Carrying Value

The carrying value and fair value of SCE's long-term debt (including current portion of long-term debt) are as follows:

	December 31, 2015		December 31, 2014	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
SCE	$ 10,616	$ 11,592	$ 9,924	$ 11,479

The fair value of SCE's short-term and long-term debt is classified as Level 2 and is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes of new issue prices and relevant credit information.

The carrying value of SCE's trade receivables and payables, other investments, and short-term debt approximates fair value.

Income Taxes

SCE estimates income taxes for each jurisdiction in which it operates. This involves estimating current period tax expense along with assessing temporary differences resulting from differing treatment of items (such as depreciation) for tax and accounting purposes. These differences result in deferred tax assets and liabilities. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are deferred and amortized to income tax expense over the lives of the properties or the term of the power purchase agreement of the respective project while production tax credits are recognized in income tax expense in the period in which they are earned.

Pursuant to an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed its federal and state income tax returns on a separate return basis.

The CPUC requires flow-through ratemaking treatment for the current tax benefit arising from certain property-related and other temporary differences which reverse over time. Flow-through items reduce current authorized revenue requirements in SCE's rate cases and result in a regulatory asset for recovery of deferred income taxes in future periods. The difference between the authorized amounts as determined in SCE's rate cases, adjusted for balancing and memorandum account activities, and the recorded flow-through items also result in increases or decreases in regulatory assets with a corresponding impact on the effective tax rate to the extent that recorded deferred amounts are expected to be recovered in future rates.

Repair Deductions

Voluntary elections were made in 2009 and 2011 to change its tax accounting method for certain tax repair costs incurred on SCE's transmission, distribution and generation assets. Incremental repair deductions represent amounts recognized for regulatory accounting purposes in excess of amounts included in the authorized revenue requirements through the General Rate Case ("GRC") proceedings. Incremental repair deductions for the years 2012 – 2014 resulted in additional income tax benefits of $133 million in 2014 and $89 million in 2013.

As part of the final decision in SCE's 2015 GRC, the CPUC adopted a rate base offset associated with these incremental tax repair deductions during 2012 – 2014. The 2015 rate base offset is $324 million and amortizes on a straight line basis over 27 years. As a result of the rate base offset included in the final decision, SCE recorded an after tax charge of $382 million during the fourth quarter of 2015 to write down the net regulatory asset for recovery of deferred income taxes related to 2012 – 2014 incremental tax repair deductions.

Accounting for Uncertainty in Income Taxes

Authoritative guidance related to accounting for uncertainty in income taxes requires an enterprise to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained upon examination. The guidance requires the disclosure of all unrecognized tax benefits, which includes both the reserves recorded for tax positions on filed tax returns and the unrecognized portion of affirmative claims.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits:

	December 31,		
(in millions)	2015	2014	2013
Balance at January 1,	$ 441	$ 532	$ 571
Tax positions taken during the current year:			
Increases	48	57	22
Tax positions taken during a prior year:			
Increases	23	—	45
Decreases[1]	(159)	(93)	(106)
Decreases for settlements during the period[2]	—	(55)	—
Balance at December 31,	$ 353	$ 441	$ 532

1 Decreases in prior year tax positions relate primarily to re-measurement of uncertain tax positions in connection with receipt of the IRS Revenue Agent Report in June 2015. See discussions in Tax Disputes below.

2 In the fourth quarter of 2014, all open tax positions were settled with the IRS for taxable year 2003 through 2006.

As of December 31, 2015 and 2014, if recognized, $256 million and $370 million, respectively, of the unrecognized tax benefits would impact SCE's effective tax rate.

Tax Disputes

Tax Years 2007 – 2009

A Revenue Agent Report was received from the IRS in February 2013 which included a proposed adjustment to disallow deductions related to certain capitalized overhead costs. A tentative agreement has been reached with the IRS regarding this matter, which if finalized, would result in a federal tax liability of approximately $64 million, including interest through December 31, 2015.

Tax Years 2010 – 2012

The IRS Revenue Agent Report was received in June 2015. As a result, SCE has re-measured its Federal and State uncertain tax positions and recorded $100 million of income tax benefits including interest and penalty during the second quarter of 2015. The Revenue Agent Report included a proposed adjustment to disallow deductions related to certain capitalized overhead expenses. A tentative agreement has been reached with the IRS regarding this matter, which if finalized, would result in a federal tax liability of approximately $9 million, including interest through December 31, 2015.

Tax years that remain open for examination by the IRS and the California Franchise Tax Board are 2007 – 2015 and 2003 – 2015, respectively.

Accrued Interest and Penalties

The total amount of accrued interest and penalties related to income tax liabilities are $40 million and $64 million at December 31, 2015 and 2014, respectively.

The net after-tax interest and penalties recognized in income tax benefit are $14 million, $16 million and $2 million for the years ended December 31, 2015, 2014 and 2013, respetively.

New Accounting Guidance

Accounting Guidance Adopted

On November 20, 2015, the FASB issued an accounting standards update on the balance sheet classification of deferred taxes. This standard requires that all deferred income tax assets and liabilities be presented as noncurrent in the consolidated balance sheet. Prior to this update, deferred income taxes for each tax-paying component of an entity would be presented in two classifications in the balance sheet: (1) a net current asset or liability and (2) a net noncurrent asset or liability. SCE has retrospectively adopted this standard as of December 31, 2015. As a result of the adoption, SCE reclassified $209 million of current deferred income tax liabilities to long-term deferred income tax liabilities on the 2014 consolidated balance sheet.

Accounting Guidance Not Yet Adopted

On May 28, 2014, the FASB issued an accounting standards update on revenue recognition including enhanced disclosures. Under the new standard, revenue is recognized when (or as) a good or service is transferred to the customer and the customer obtains control of the good or service. On July 9, 2015, the FASB approved a one-year deferral, updating the effective date to January 1, 2018. The accounting standard update allows for the adoption using a retrospective application or a modified retrospective application. SCE is currently evaluating this new guidance and cannot determine the impact of this standard at this time. SCE anticipates adopting the standard using the modified retrospective application which means that we would recognize the cumulative effect of initially applying the revenue standard as an adjustment to the opening balance of retained earnings in 2018.

On April 7, 2015, the FASB issued an accounting standards update that will require debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability, consistent with debt discounts. Currently, these costs are presented as a deferred charge asset. SCE will adopt this guidance in the first quarter of 2016. The adoption of this accounting standards update will not have a material impact on SCE's consolidated financial statements.

On April 15, 2015, the FASB issued an accounting standard update on fees paid by a customer for software licenses. This new standard provides guidance about whether a cloud computing arrangement includes a software license which may be capitalized in certain circumstances. If a cloud computing arrangement does not include a software license, then the arrangement should be accounted for as a service contract. SCE will adopt this guidance prospectively, effective January 1, 2016. The adoption of this standard will not have a material impact on SCE's consolidated financial statements.

On January 5, 2016, the FASB issued an accounting standards update that amends the guidance on the classification and measurement of financial instruments. The amendments require equity investments (excluding those accounted for under the equity method or those that result in consolidation) to be measured at fair value, with changes in fair value recognized in net income. Currently, these changes are recorded in other comprehensive income. It also amends certain disclosure requirements associated with the fair value of financial instruments. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category and form of financial asset. SCE will adopt this guidance effective January 1,

2018. The adoption of this standard is not expected to have a material impact on SCE's consolidated financial statements.

Power Purchase Agreements

SCE enters into power purchase agreements in the normal course of business. A power purchase agreement may be considered a variable interest in a variable interest entity. Under this classification, the power purchase agreement is evaluated to determine if SCE is the primary beneficiary in the variable interest entity, in which case, such entity would be consolidated. None of SCE's power purchase agreements resulted in consolidation of a variable interest entity at December 31, 2015 and 2014.

A power purchase agreement may also contain a lease for accounting purposes. This generally occurs when a power purchase agreement (signed or modified after June 30, 2003) designates a specific power plant in which the buyer purchases substantially all of the output and does not otherwise meet a fixed price per unit of output exception. SCE has a number of power purchase agreements that contain leases. SCE's recognition of lease expense conforms to the ratemaking treatment for SCE's recovery of the cost of electricity and is recorded in purchased power. The majority of these agreements are classified as leases as electricity is delivered at rates defined in power sales agreements.

A power purchase agreement that does not contain a lease may be classified as a derivative subject to a normal purchase and sale exception, in which case the power purchase agreement is classified as an executory contract and accounted for on an accrual basis. Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not meet the definition of a derivative or meet the normal purchase and sale exception. SCE purchases power under certain contracts that are not eligible for the normal purchase and sale exception and are recorded as a derivative on the consolidated balance sheets at fair value.

Power purchase agreements that do not meet the above classifications are accounted for on an accrual basis.

Variable Interest Entities

A variable interest entity ("VIE") is defined as a legal entity that meets one of two conditions: (1) the equity owners do not have sufficient equity at risk, or (2) the holders of the equity investment at risk, as a group, lack any of the following three characteristics: decision-making rights, the obligation to absorb losses, or the right to receive the expected residual returns of the entity. The primary beneficiary is identified as the variable interest holder that has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE. Commercial and operating activities are generally the factors that most significantly impact the economic performance of such VIEs. Commercial and operating activities include construction, operation and maintenance, fuel procurement, dispatch and compliance with regulatory and contractual requirements.

Variable Interest in VIEs that are not Consolidated

Power Purchase Contracts

SCE has power purchase agreements ("PPAs") that are classified as variable interests in VIEs, including tolling agreements through which SCE provides the natural gas to fuel the plants and contracts with qualifying facilities ("QFs") that contain variable pricing provisions based on the price of natural gas. SCE has concluded that it is not the primary beneficiary of these VIEs since it does not control the commercial and operating activities of these entities. Since payments for capacity are the primary source of income, the most significant economic activity for these VIEs is the operation and maintenance of the power plants.

As of the balance sheet date, the carrying amount of assets and liabilities in SCE's consolidated balance sheet that relate to its involvement with VIEs result from amounts due under the PPAs or the fair value of those derivative contracts. Under these contracts, SCE recovers the costs incurred through demonstration of compliance with its CPUC-approved long-term power procurement plans. SCE has no residual interest in the entities and has not provided or guaranteed any debt or equity support, liquidity arrangements, performance guarantees or other commitments associated with these contracts other than the purchase commitments. As a result, there is no significant potential exposure to loss to SCE from its variable interest in these VIEs. The aggregate contracted capacity dedicated to SCE from these VIE projects was 4,062 MW and 5,641 MW at December 31, 2015 and 2014, respectively, and the amounts that SCE paid to these projects were $640 million and $739 million for the years ended December 31, 2015 and 2014, respectively. These amounts are recoverable in customer rates, subject to reasonableness review.

Unconsolidated Trusts of SCE

SCE Trust I, Trust II, Trust III and Trust IV were formed in 2012, 2013, 2014 and 2015 respectively, for the exclusive purpose of issuing the 5.625%, 5.10%, 5.75% and 5.375% trust preference securities, respectively ("trust securities"). The trusts are VIEs. SCE has concluded that it is not the primary beneficiary of these VIEs as it does not have the obligation to absorb the expected losses or the right to receive the expected residual returns of the trusts. SCE Trust I, Trust II, Trust III and Trust IV issued trust securities in the face amount of $475 million, $400 million, $275 million and $325 million, respectively, (cumulative, liquidation amount of $25 per share) to the public and $10,000 of common stock each to SCE. The trusts invested the proceeds of these trust securities in Series F, Series G, Series H and Series J Preference Stock issued by SCE in the principal amount of $475 million, $400 million, $275 million and $325 million (cumulative, $2,500 per share liquidation value), respectively, which have substantially the same payment terms as the trust securities.

The Series F, Series G, Series H and Series J Preference Stock and the corresponding trust securities do not have a maturity date. Upon any redemption of any shares of the Series F, Series G, Series H or Series J Preference Stock, a corresponding dollar amount of trust securities will be redeemed by the applicable trust. The applicable trust will make distributions at the same rate and on the same dates on the applicable series of trust securities when and if the SCE board of directors declares and makes dividend payments on the related Preference Stock. The applicable trusts will use any dividends it receives on the related Preference Stock to make its corresponding distributions on the applicable series of trust securities. If SCE does not make a dividend payment to any of these trusts, SCE would be prohibited from paying dividends on its common stock. SCE has fully and unconditionally guaranteed the payment of the trust securities and trust distributions, if and when SCE pays dividends on the related Preference Stock.

The Trust I, Trust II and Trust III balance sheets as of December 31, 2015, and 2014 consisted of investments of $475 million, $400 million and $275 million in the Series F, Series G and Series H Preference Stock respectively, $475 million, $400 million and $275 million of trust securities, respectively and $10,000 each of common stock. The Trust IV balance sheet as of December 31, 2015 consisted of investments of $325 million in the Series J Preference Stock, $325 million of trust securities, and $10,000 of common stock.

The following table provides a summary of the trusts' income statements:

	Years ended December 31,			
(in millions)	Trust I	Trust II	Trust III	Trust IV
2015				
Dividend income	$ 27	$ 20	$ 16	$ 6
Dividend distributions	27	20	16	6
2014				
Dividend income	$ 27	$ 20	$ 13	*
Dividend distributions	27	20	13	*
2013				
Dividend income	$ 27	$ 19	*	*
Dividend distributions	27	19	*	*

* Not applicable

BALANCE SHEET

Allowance for Uncollectible Accounts

Allowances for uncollectible accounts are provided based upon a variety of factors, including historical amounts written-off, current economic conditions and assessment of customer collectability.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments. Cash equivalents are stated at fair value.

Cash is temporarily invested until required for check clearing. Checks issued, but not yet paid by the financial institution, are reclassified from cash to accounts payable were $158 million and $177 million at December 31, 2015 and 2014, respectively.

Debt and Credit Agreements

Long-Term Debt

During the first quarter of 2015, SCE issued $550 million of 1.845% amortizing first and refunding mortgage bonds due in 2022, $325 million of 2.4% first and refunding mortgage bonds due in 2022, and $425 million of 3.6% first and refunding mortgage bonds due in 2045. The proceeds from these bonds were used to repay outstanding debt and for general corporate purposes. The $550 million amortizing first and refunding mortgage bonds and the $325 million of first and refunding mortgage bonds have been designated as a financing of the San Onofre regulatory asset.

During the second quarter of 2015, SCE reissued $56 million of 1.875% pollution-control bonds due in 2029 and $75 million of 1.875% pollution-control bonds due in 2031. The proceeds were used to repay commercial paper borrowings and for general corporate purposes.

SCE long-term debt maturities over the next five years are the following:

(in millions)		
2016	$	79
2017		579
2018		479
2019		79
2020		79

Liens and Security Interests

Almost all of SCE's properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2015, SCE was in compliance with this debt covenant.

Credit Agreements and Short-Term Debt

The following table summarizes the status of the credit facilities at December 31, 2015:

(in millions)		
Commitment	$	2,750
Outstanding borrowings		(49)
Outstanding letters of credit		(125)
Amount available	$	2,576

SCE has a multi-year revolving credit facility of $1.25 billion, maturing in July 2020. SCE's credit facility is generally used to support commercial paper borrowings and letters of credit issued for procurement-related collateral requirements, balancing account undercollections and for general corporate purposes, including working capital requirements to support operations and capital expenditures.

At December 31, 2015, commercial paper supported by SCE's credit facility was $49 million at a weighted-average interest rate of 0.51%. At December 31, 2015, letters of credit issued under SCE's credit facility aggregated $125 million and are scheduled to expire in twelve months or less. At December 31, 2014, the outstanding commercial paper was $367 million at a weighted-average interest rate of 0.40%.

Inventory

Inventory is primarily composed of materials, supplies and spare parts, and stated at the lower of cost or market, cost being determined by the average cost method.

Energy Credits and Allowances

Renewable energy certificates or credits ("RECs") represent rights established by governmental agencies for the environmental, social, and other non-power qualities 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, including California. Retail sellers of electricity obtain RECs through renewable power purchase agreements, internal generation or separate purchases in the market to comply with renewables portfolio standards ("RPS") established by certain governmental agencies. RECs are the mechanism used to verify renewables portfolio standard compliance and are recognized at the lower of weighted-average cost or market when amounts purchased are in excess of the amounts needed to comply with RPS requirements. The cost of purchased RECs is recoverable as part of the cost of purchased power.

SCE is allocated greenhouse gas ("GHG") allowances annually which it is then required to sell into quarterly auctions. GHG proceeds from the auctions are recorded as a regulatory liability to be refunded to customers. SCE purchases GHG allowances in quarterly auctions or from counterparties to satisfy its GHG emission compliance obligations and recovers such costs of GHG allowances from customers. GHG allowances held for use are stated, similar to an inventory method, at the lower of weighted-average cost or market.

Preferred and Preference Stock of Utility

SCE's authorized shares are: $100 cumulative preferred – 12 million shares, $25 cumulative preferred – 24 million shares and preference with no par value – 50 million shares. SCE's outstanding shares are not subject to mandatory redemption. There are no dividends in arrears for the preferred or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred shares are redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred shares were issued or redeemed in the years ended December 31, 2015, 2014 and 2013. There is no sinking fund requirement for redemptions or repurchases of preferred shares.

Shares of SCE's preference stock rank junior to all of the preferred stock and senior to all common stock. Shares of SCE's preference stock are not convertible into shares of any other class or series of SCE's capital stock or any other security. There is no sinking fund requirement for redemptions or repurchases of preference shares.

Shares of Series D and E preference stock, issued in 2011 and 2012, respectively, may be redeemed at par, in whole or in part, after March 1, 2016 and February 1, 2022, respectively. Shares of Series F, G, H and J preference stock, issued in 2012, 2013, 2014 and 2015, respectively, may be redeemed at par, in whole, but not in part, at any time prior to June 15, 2017, March 15, 2018, March 15, 2024 and September 15, 2025, respectively, if certain changes in tax or investment company laws occur. After June 15, 2017, March 15, 2018, March 15, 2024 and September 15, 2025, SCE may redeem the Series F, G, H and J shares, respectively, at par, in whole or in part. For shares of Series H and J preference stock, distributions will accrue and be payable at a floating rate from and including March 15, 2024 and September 15, 2025, respectively. Shares of Series F, G, H and J preference stock were issued to SCE Trust I, SCE Trust II, SCE Trust III and SCE Trust IV, respectively, special purpose entities formed to issue trust securities. The proceeds from the sale of the shares of Series J were used to redeem $325 million of the Company's Series A preference stock. Preference shares are not subject to mandatory redemption.

At December 31, 2015, declared dividends related to SCE's preferred and preference stock were $14 million.

During the first quarter of 2016, SCE issued $300 million of 5.45% Series K preference stock (120,004 shares; cumulative, $2,500 liquidation value) to SCE Trust V, a special purpose entity formed to issue trust securities. The Series K preference stock may be redeemed at par, in whole, but not in part, at any time prior to March 15, 2026 if certain changes in tax or investment company laws occur. After March 15, 2026, SCE may redeem the Series K shares at par, in whole or in part and distributions will accrue and be payable at a floating rate. The shares are not subject to mandatory redemption. The proceeds were used to redeem $125 million of the Company's Series D preference stock and for general corporate purposes.

Property, Plant and Equipment

Plant additions, including replacements and betterments, are capitalized. SCE capitalizes as part of plant additions direct material and labor and indirect costs such as construction overhead, administrative and general costs, pension and benefits, and property taxes. The CPUC authorizes a rate for each of the indirect costs which are allocated to each project based on either labor or total costs. In addition, allowance for funds used during construction (“AFUDC”) is capitalized by SCE for certain projects.

AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction and is capitalized during certain plant construction. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. AFUDC equity represents a method to compensate SCE for the estimated cost of equity used to finance utility plant additions and is recorded as part of construction in progress. AFUDC equity was $87 million, $65 million and $72 million in 2015, 2014 and 2013, respectively. AFUDC debt was $31 million, $25 million and $33 million in 2015, 2014 and 2013, respectively.

Under the San Onofre OII Settlement Agreement, the unamortized portion of SCE's investment other than nuclear fuel may, at SCE's option, be excluded from SCE's capital structure for purposes of determining regulatory capital requirements and to allow SCE to finance those assets solely with debt. The terms of the San Onofre OII Settlement Agreement provide that if SCE selects the debt financing option and finances these regulatory assets at a cost lower than the return authorized by the San Onofre OII Settlement Agreement, the savings will be shared equally between customers and SCE. In January 2015, SCE issued $550 million of 1.845% amortizing first and refunding mortgage bonds due in 2022 and $325 million of 2.40% first and refunding mortgage bonds due in 2022. These bonds have been designated as a financing of the San Onofre regulatory asset. Beginning in 2015, SCE will exclude these bonds from the AFUDC rate calculation as they are not a source of funds for construction financing. However, FERC rules prescribe long-term debt used in the AFUDC rate calculation to be based upon values as of the end of the preceding year. As of year-end 2014, SCE did not have any long-term debt related to the San Onofre regulatory asset, and thus AFUDC in 2015 was not impacted by the aforementioned bonds.

In 2007, FERC issued an order granting ROE incentive adders, recovery of the ROE and incentive adders during the construction phase (referred to CWIP) and recovery of abandoned plant costs for many of SCE’s transmission projects. In addition, the FERC granted an incentive for CAISO participation. The order permits SCE to include 100% of prudently-incurred capital expenditures in rate base during construction of the projects and earn a return on equity, rather than capitalizing AFUDC.

If SCE had not implemented this transmission incentive mechanism, and continued to follow FERC Uniform System of Accounts for these projects, approximately $411 million and $388 million would have been capitalized as of December 31, 2015 and 2014, respectively. The following is a partial balance sheet that includes the amounts not capitalized because of the transmission rate incentives.

(in millions)	December 31, 2015	December 31, 2014
Utility property, plant and equipment	$ 42,035	$ 39,312
Construction work in progress	3,252	3,454
Total utility property plant and equipment	45,287	42,766
(Less) accumulated provision for depreciation, amortization and depletion	(12,860)	(12,485)
Net utility property, plant and equipment	$ 32,427	$ 30,281

Estimated useful lives (authorized by the CPUC) and weighted-average useful lives of SCE's property, plant and equipment, are as follows:

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	10 years to 57 years	38 years
Distribution plant	20 years to 60 years	43 years
Transmission plant	40 years to 65 years	52 years
General plant and other	5 years to 60 years	22 years

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $1.42 billion, $1.33 billion and $1.31 billion for 2015, 2014 and 2013, respectively. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 3.9%, 4.0% and 4.2% for 2015, 2014 and 2013, respectively. Replaced or retired property costs are charged to accumulated depreciation.

Nuclear fuel for the Palo Verde Nuclear Power Plant is recorded as utility plant (nuclear fuel in the fabrication and installation phase is recorded as construction in progress) in accordance with CPUC ratemaking procedures. Nuclear fuel is amortized using the units of production method.

Major Maintenance

Major maintenance costs for SCE's power plant facilities and equipment are expensed as incurred.

Capitalized Software Costs

SCE capitalizes costs incurred during the application development stage of internal use software projects to property, plant, and equipment. SCE amortizes capitalized software costs ratably over the expected lives of the software, ranging from 5 to 15 years and commencing upon operational use. At December 31, 2015 and 2014, capitalized software costs included in general plant and other above, were $1.4 billion and $1.7 billion and accumulated amortization was $892 million and $1.0 billion, respectively. Amortization expense for capitalized software was $268 million, $271 million and $251 million in 2015, 2014 and 2013, respectively. At December 31, 2015, amortization expense is estimated to be approximately $237 million annually for 2016 through 2020.

Jointly Owned Utility Projects

SCE owns undivided interests in several generating assets for which each participant provides its own financing. SCE's proportionate share of these assets is reflected in the consolidated balance sheets and included in the above table. SCE's proportionate share of expenses for each project is reflected in the consolidated statements of income. A portion of the investments in Palo Verde generating stations is included in regulatory assets on the consolidated balance sheets.

The following is SCE's investment in each asset as of December 31, 2015:

(in millions)	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Nuclear Fuel (at amortized cost)	Net Book Value	Ownership Interest
Transmission systems:						
Eldorado	$ 186	$ 38	$ 20	$ —	$ 204	59%
Pacific Intertie	191	11	79	—	123	50%
Generating station:						
Palo Verde (nuclear)	1,928	62	1,538	131	583	16%
Total	$ 2,305	$ 111	$ 1,637	$ 131	$ 910	

In addition, SCE has ownership interests in jointly owned power poles with other companies.

Asset Retirement Obligations

The fair value of a liability for an asset retirement obligation ("ARO") is recorded in the period in which it is incurred, including a liability for the fair value of a conditional ARO, if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. When an ARO liability is initially recorded, SCE capitalizes the cost by increasing the carrying amount of the related long-lived asset. For each subsequent period, the liability is increased for accretion expense and the capitalized cost is depreciated over the useful life of the related asset.

AROs related to decommissioning of SCE's nuclear power facilities are based on site-specific studies conducted as part of each Nuclear Decommissioning Cost Triennial Proceeding ("NDCTP") conducted before the CPUC. Revisions of an ARO are established for updated site-specific decommissioning cost estimates. SCE adjusts its nuclear decommissioning obligation into a nuclear-related ARO regulatory asset and also records an ARO regulatory liability as a result of timing differences between the recognition of costs and the recovery of costs through the ratemaking process.

The following table summarizes the changes in SCE's ARO liability, including San Onofre and Palo Verde:

(in millions)	December 31, 2015	December 31, 2014
Beginning balance	$ 2,819	$ 3,418
Accretion[1]	173	192
Revisions	(14)	(790)
Liabilities settled	(216)	(1)
Ending balance	$ 2,762	$ 2,819

1 An ARO represents the present value of a future obligation. Accretion is an increase in the liability to account for the time value of money resulting from discounting.

SCE has not recorded an asset retirement obligation for assets that are expected to operate indefinitely. As SCE cannot estimate a settlement date (or range of potential settlement dates) or make reasonable estimates of fair value of these assets. As such, ARO liabilities are not recorded for certain retirement activities, including certain hydroelectric facilities.

The recorded liability to decommission SCE's nuclear power facilities is $2.7 billion as of December 31, 2015, based on decommissioning studies performed in 2010 for Palo Verde, in 2011 for San Onofre Unit 1 and in 2014 for San Onofre Units 2 and 3 following the decision to permanently retire San Onofre. During 2014, an updated cost estimate for San Onofre Units 2 and 3 resulted in a decrease to the ARO liability of $688 million. In December 2014, SCE received a decision on its NDCTP for Palo Verde and San Onofre Unit 1. The decision resulted in a $253 million decrease for Palo Verde and $124 million increase for San Onofre Unit 1 ARO liabilities.

Impairment of Long-Lived Assets

Impairments of long-lived assets are evaluated based on a review of estimated future cash flows expected to be generated whenever events or changes in circumstances indicate that the carrying amount of such investments or assets may not be recoverable. If the carrying amount of a long-lived asset exceeds expected future cash flows, undiscounted and without interest charges, an impairment loss is recognized in the amount of the excess of fair value over the carrying amount. Fair value is determined via market, cost and income based valuation techniques, as appropriate. SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from customers.

Due to the decision to early retire San Onofre Units 2 and 3, GAAP required reclassification of the amounts recorded in property, plant and equipment and related tangible operating assets to a regulatory asset to the extent that management concluded it was probable of recovery through future rates. Regulatory assets may also be recorded to the extent management concludes it is probable that direct and indirect costs incurred to retire Units 2 and 3 as of each reporting date are recoverable through future rates. In accordance with these requirements and as a result of its decision to retire San Onofre Units 2 and 3, SCE reclassified $1,521 million of its total investment in San Onofre at May 31, 2013 to a regulatory asset ("San Onofre Regulatory Asset") and recorded an impairment charge of $575 million ($365 million after-tax) in the second quarter of 2013.

In March 2014, SCE entered into a settlement agreement with The Utility Reform Network ("TURN"), the CPUC's Office of Ratepayer Advocates ("ORA"), SDG&E, the Coalition of California Utility Employees, and Friends of the Earth (together, the "Settling Parties"). In September 2014, SCE and the Settling Parties entered into an Amended and Restated Settlement Agreement (the "San Onofre OII Settlement Agreement") which was approved by the CPUC on November 20, 2014. As a result of these developments, SCE recorded an additional pre-tax charge of approximately $163 million (approximately $72 million after-tax) during 2014. Including amounts previously recorded in 2013, the total impact of the San Onofre OII Settlement Agreement was a pre-tax charge of $738 million (approximately $437 million after-tax).

Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. CPUC authorized balancing account mechanisms require SCE to refund or recover any differences between forecasted and actual costs. The CPUC has authorized balancing accounts for specified costs or programs such as fuel, purchased-power, demand-side management programs, nuclear decommissioning and public purpose programs. Certain of these balancing accounts include a return on rate base of 7.90% in 2015 and 2014. The CPUC also authorizes the use of a balancing account to recover from or refund to customers differences in revenue resulting from actual and forecasted electricity sales.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts.

Regulatory Assets

SCE's regulatory assets related to energy derivatives are primarily an offset to unrealized losses on derivatives. The regulatory asset changes based on fluctuations in the fair market value of the contracts, in which the original contracts expire in 2 to 45 years.

SCE's regulatory assets related to deferred income taxes represent tax benefits passed through to customers. The CPUC requires SCE to flow through certain deferred income tax benefits to customers by reducing electricity rates, thereby deferring recovery of such amounts to future periods. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its regulatory assets related to deferred income taxes over the life of the assets that give rise to the accumulated deferred income taxes, approximately from 1 to 60 years.

SCE's regulatory assets related to pensions and other post-retirement plans represent the unfunded net loss and prior service costs of the plans. This amount is being recovered through rates charged to customers.

SCE's unamortized investments primarily include nuclear assets related to Palo Verde and legacy meters retired as part of the Edison SmartConnect® program. Nuclear assets related to Palo Verde are expected to be recovered by 2047 and earned a return of 7.90% in 2015 and 2014. SCE's unamortized investments related to legacy meters are expected to be recovered by 2017 and earned a rate of return of 6.46% in 2015 and 2014.

In accordance with the San Onofre OII Settlement Agreement, SCE is authorized to recover in rates its San Onofre regulatory asset, generally over a ten-year period commencing February 1, 2012. Under the San Onofre OII Settlement Agreement, SCE was allowed to earn a rate of return of 2.62% for the period 2014 – 2015 and is authorized to continue to earn this rate as adjusted during the amortization period thereafter with changes in SCE's authorized return on debt and preferred equity. SCE's regulatory assets related to San Onofre nuclear fuel will earn a return equal to commercial paper rate that the CPUC uses to calculate interest on balancing accounts.

SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the original amortization period of the reacquired debt over periods ranging from 1 to 35 years.

SCE's regulatory assets related to environmental remediation represents a portion of the costs incurred at certain sites that SCE is allowed to recover through customer rates.

Regulatory Liabilities

SCE's regulatory liabilities related to costs of removal represent differences between asset removal costs recorded and amounts collected in rates for those costs.

SCE's regulatory liability equal to nuclear decommissioning trust assets in excess of the related asset retirement obligations which represent future refunds to customers if such assets are not used to decommission the related nuclear facilities. The decrease in this regulatory liability resulted from SCE's obtaining access of decommissioning funds for Units 2 and 3 and changes in market value for decommissioning trust funds for nuclear assets.

Net Regulatory Balancing Accounts

Balancing account over and under collections represent differences between cash collected in current rates for specified forecasted costs and such costs that are actually incurred. Undercollections are recorded as regulatory balancing account assets. Overcollections are recorded as regulatory balancing account liabilities. With some exceptions, SCE seeks to adjust rates on an annual basis or at other designated times to recover or refund the balances recorded in its balancing accounts. Regulatory balancing accounts that SCE does not expect to collect or refund in the next 12 months are reflected in the long-term section of the consolidated balance sheets. Regulatory balancing accounts do not have the right of offset and are presented gross in the consolidated balance sheets. Under and over collections accrue interest based on a three-month commercial paper rate published by the Federal Reserve.

The 2015 GRC established a tax accounting memorandum account (referred to as "TAMA"), which provides that additional 2015 – 2017 tax benefits or costs associated with the following events be tracked: (1) tax accounting method changes, (2) changes in tax laws and regulations impacting depreciation or tax repair deductions, (3) forecasted and actual differences in tax repair deductions, and (4) the impact, if any, of a private letter ruling related to compliance with normalization regulations of the IRS. As a result of this memorandum account, together with the balancing account for pole loading expenditures, any differences between the forecasted tax repair deductions and actual tax repair deductions for 2015 – 2017 will be adjusted annually through customer rates. The TAMA will also reflect the revenue requirement impact of the extension of bonus depreciation.

SCE had participated in proceedings seeking recovery of refunds from certain sellers of electricity and natural gas during the energy crisis in California in 2000 – 2001. SCE is authorized to refund to customers any refunds actually realized by SCE, net of litigation costs and amounts retained by SCE as a shareholder incentive pursuant to an established sharing arrangement. During 2014, the FERC approved generator settlement agreements which resulted in total refunds to customers of $219 million of which $15 million is subject to a shareholder incentive.

Related Party Transactions

SCE provides and receives various services to and from its subsidiaries and affiliates. Services provided to Edison International by SCE are priced at fully loaded cost (i.e., direct cost of good or service and allocation of overhead cost). Specified administrative services such as payroll, employee benefit programs, all performed by Edison International or SCE employees, are shared among all affiliates of Edison International. Costs are allocated based on one of the following formulas: percentage of time worked, equity in investment and advances, number of employees, or multi-factor (operating revenues, operating expenses, total assets and number of employees). Edison International allocates various corporate administrative and general costs to SCE and other subsidiaries using established allocation factors.

INCOME STATEMENT

Revenue Recognition

Revenue is recognized when electricity is delivered and includes amounts for services rendered but unbilled at the end of each reporting period. Rates charged to customers are based on CPUC- and FERC-authorized revenue requirements. CPUC rates are implemented subsequent to final approval.

CPUC rates decouple authorized revenue from the volume of electricity sales. Differences between amounts collected and authorized levels are either collected from or refunded to customers, and therefore, SCE earns revenue equal to amounts authorized. FERC rates also decouple revenue from volume of electricity sales. In November 2013, the FERC approved a formula rate effective January 1, 2012 to determine SCE's FERC transmission revenue requirement, including its construction work in progress ("CWIP") revenue requirement. Under operation of the formula rate, transmission revenue will be updated to actual cost of service annually. Differences between amounts collected and determined under the formula rate are either collected from or refunded to customers, and therefore, SCE earns revenue based on estimates of recorded rate base costs under the FERC formula rate.

SCE bills certain sales and use taxes levied by state or local governments to its customers. Included in these sales and use taxes are franchise fees, which SCE pays to various municipalities (based on contracts with these municipalities) in order to operate within the limits of the municipality. SCE bills these franchise fees to its customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SCE's ability to collect from the customer, are accounted for on a gross basis and reflected in electric utility revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as revenue were $138 million, $134 million and $116 million in 2015, 2014 and 2013, respectively. When SCE bills and collects taxes from customers, these taxes are remitted to the taxing authorities and are not recognized as electric utility revenue.

CASH FLOW STATEMENT

Supplemental Cash Flows Information

Supplemental cash flows information is:

(in millions)	Years ended December 31, 2015	2014	2013
Cash payments (receipts) for interest and taxes:			
Interest, net of amounts capitalized	$ 478	$ 487	$ 462
Tax payments (refunds), net	144	(88)	28
Non-cash financing and investing activities:			
Dividends declared but not paid:			
Common stock	$ —	$ 147	$ —
Preferred and preference stock	14	18	30
Details of debt exchange:			
Pollution-control bonds redeemed (2.875%)	(203)	—	—
Pollution-control bonds issued (1.875%)	203	—	—

SCE's accrued capital expenditures at December 31, 2015, 2014 and 2013 were $543 million, $837 million and $661 million, respectively. Accrued capital expenditures will be included as an investing activity in the consolidated statements of cash flow in the period paid.

During 2015, an SCE power contract classified as a capital lease was amended, which resulted in a reduction in the lease obligations and asset by $147 million.

Item 2. Significant Contingencies

Contingencies

In addition to the matters disclosed in these Notes, SCE was involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these other proceedings will not, individually or in the aggregate, materially affect its results of operations or liquidity.

Long Beach Service Interruptions

In July 2015, SCE's customers who are served via the network portion of SCE's electric system in Long Beach, California experienced service interruptions due to multiple underground vault fires and underground cable failures. No personal injuries have been reported in connection with these events. SCE instituted an internal investigation and commissioned an external investigation of these events and their causes, which revealed that the main cause of the interruptions was a lack of adequate management oversight of the downtown network system. The investigations also revealed deficiencies in maintaining the knowledge base on the configuration and operation of the system, and a lack of sophisticated controls needed to more efficiently and effectively prevent and respond to the cascading events that occurred. These events and their causes are also being investigated by the CPUC's SED. SCE is unable to estimate a possible loss or range of loss associated with any penalties that may be imposed by the CPUC related to this matter. Subject to applicable deductibles, SCE is generally insured against customer claims arising from these service interruptions.

Environmental Remediation

SCE records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operation and maintenance, monitoring and site closure. Unless there is a single probable amount, SCE records the lower end of this reasonably likely range of costs at undiscounted amounts as timing of cash flows is uncertain.

At December 31, 2015, SCE's recorded estimated minimum liability to remediate its 19 identified material sites (sites in which the upper end of the range of the costs is at least $1 million) was $131 million, including $80 million related to San Onofre. In addition to these sites, SCE also has 39 immaterial sites for which the total minimum recorded liability was $3 million. Of the $134 million total environmental remediation liability for SCE, $129 million has been recorded as a regulatory asset. SCE expects to recover $47 million through an incentive mechanism that allows SCE to recover 90% of its environmental remediation costs at certain sites (SCE may request to include additional sites) and $82 million through a mechanism that allows SCE to recover 100% of the costs incurred at certain sites through customer rates. SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs at the identified material sites and immaterial sites could exceed its recorded liability by up to $164 million and $8 million, respectively. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

SCE expects to clean up and mitigate its identified sites over a period of up to 30 years. Remediation costs for each of the next five years are expected to range from $7 million to $26 million. Costs incurred for years ended December 31, 2015, 2014 and 2013 were $5 million, $4 million and $8 million, respectively.

Based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, SCE believes that costs ultimately recorded will not materially affect its results of operations, financial position or cash flows. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to estimates.

Nuclear Insurance

Federal law limits public offsite liability claims for bodily injury and property damage from a nuclear incident to the amount of available financial protection, which is currently approximately $13.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($375 million) through a Facility Form issued by American Nuclear Insurers ("ANI"). The balance is covered by a loss sharing program among nuclear reactor licensees. If a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site, all nuclear reactor licensees could be required to contribute their share of the liability in the form of a deferred premium.

The ANI Facility Form coverage includes broad liability protection for bodily injury or offsite property damage caused by nuclear material at San Onofre, or while in transit to or from San Onofre. The Facility Form, however, includes several exclusions. First, it excludes onsite property damage to the nuclear facility itself and onsite cleanup costs, but as discussed below SCE maintains separate NEIL property damage coverage for such events. Second, tort claims of onsite workers are excluded, but SCE also maintains an ANI Master Worker Form policy that provides coverage for non-licensee workers. This program provides a shared industry aggregate limit of $375 million. Industry losses covered by this program could reduce limits available to SCE. Third, offsite environmental costs arising out of government orders or directives, including those issued under the Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA, are excluded, with minor exceptions from clearly identifiable accidents.

Based on its ownership interests, SCE could be required to pay a maximum of approximately $255 million per nuclear incident. However, it would have to pay no more than approximately $38 million per incident in any one year. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further federal revenue.

NEIL, a mutual insurance company owned by entities with nuclear facilities, issues nuclear property damage and accidental outage insurance policies. The amount of nuclear property insurance purchased for San Onofre and Palo Verde exceeds the minimum federal requirement of $1.06 billion. These policies include coverage for decontamination liability. Property damage insurance also covers damages caused by acts of terrorism up to specified limits. Additional outage insurance covers part of replacement power expenses during an accident-related nuclear unit outage. The accidental outage insurance at San Onofre has been canceled as a result of the permanent retirement, but that insurance continues to be in effect at Palo Verde.

If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately $45 million per year. Insurance premiums are charged to operating expense.

San Onofre Related Matters

Replacement steam generators were installed at San Onofre in 2010 and 2011. On January 31, 2012, a leak suddenly occurred in one of the heat transfer tubes in San Onofre's Unit 3 steam generators. The Unit was safely taken off-line and subsequent inspections revealed excessive tube wear. Unit 2 was off-line for a planned outage when areas of unexpected tube wear were also discovered. On June 6, 2013, SCE decided to permanently retire Units 2 and 3.

Settlement of San Onofre CPUC Proceedings

In November 2014, the CPUC approved the San Onofre OII Settlement Agreement that SCE had entered into with TURN, ORA, SDG&E, the Coalition of California Utility Employees, and Friends of the Earth. The San Onofre OII Settlement Agreement resolved the CPUC's investigation regarding the Steam Generator Replacement Project at San Onofre and the related outages and subsequent shutdown of San Onofre. The San Onofre OII Settlement Agreement does not affect proceedings related to recoveries from third parties described below, but does describe how shareholders and customers will share any recoveries.

Challenges related to San Onofre CPUC Proceedings

A federal lawsuit challenging the CPUC's authority to permit rate recovery of San Onofre costs and an application to the CPUC for rehearing of its decision approving the San Onofre OII Settlement Agreement were filed in November and December 2014, respectively. In April 2015, the federal lawsuit was dismissed with prejudice and the plaintiffs in that case appealed the dismissal to the Ninth Circuit in May 2015. Both the appeal and the application for rehearing remain pending.

In April 2015, the Alliance for Nuclear Responsibility ("A4NR") filed a petition to modify the CPUC's decision approving the San Onofre OII Settlement Agreement based on SCE's alleged failures to disclose communications between SCE and CPUC decision-makers pertaining to issues in the San Onofre OII. The petition seeks the reversal of the decision approving the San Onofre OII Settlement Agreement and reopening of the OII proceeding. Subsequently, TURN and ORA filed responses supporting A4NR's petition to reopen the San Onofre OII proceeding. In August 2015, ORA filed its own petition to modify the CPUC's decision approving the San Onofre OII Settlement Agreement seeking to set aside the settlement and reopen the San Onofre OII proceeding. SCE and SDG&E responded to this petition in September 2015. Both petitions remain pending before the CPUC.

In July 2015, a purported securities class action lawsuit was filed in federal court against Edison International, its Chief Executive Officer and Chief Financial Officer and was later amended to include SCE's former President as a defendant. The lawsuit alleges that the defendants violated the securities laws by failing to disclose that Edison International had *ex parte* contacts with CPUC decision-makers regarding the San Onofre OII that were either unreported or more extensive than initially reported. The complaint purports to be filed on behalf of a class of persons who acquired Edison International common stock between March 21, 2014 and June 24, 2015.

Subsequently and also in July 2015, a federal shareholder derivative lawsuit was filed against members of the Edison International Board of Directors for breach of fiduciary duty and other claims. The federal derivative lawsuit is based on similar allegations to the federal class action securities lawsuit and seeks monetary damages, including punitive damages, and various corporate governance reforms. An additional federal shareholder derivative lawsuit making essentially the same allegations was filed in August and was subsequently consolidated with the July 2015 federal derivative lawsuit.

In October 2015, a shareholder derivative lawsuit was filed in California state court against members of the Edison International Board of Directors for breach of fiduciary duty and other claims, making similar allegations to those in the federal derivative lawsuits discussed above.

In November 2015, a purported securities class action lawsuit was filed in federal court against Edison International, its Chief Executive Officer and Treasurer by an Edison International employee, alleging claims under the Employee Retirement Income Security Act ("ERISA"). The complaint purports to be filed on behalf of a class of Edison International employees who were participants in the Edison 401(k) Savings Plan and invested in the Edison International Stock Fund between March 27, 2014 and June 24, 2015. The complaint alleges that defendants breached their fiduciary duties because they knew or should have known that investment in the Edison International Stock Fund was imprudent because the price of Edison International common stock was artificially inflated due to

Edison International's alleged failure to disclose certain *ex parte* communications with CPUC decision-makers related to the San Onofre OII.

SCE cannot predict the outcome of these proceedings.

Ex Parte Communications

In February 2015, SCE filed in the San Onofre OII proceeding a Late-Filed Notice of Ex Parte Communication regarding a meeting in March 2013 between an SCE senior executive and the president of the CPUC, both of whom have since retired from their respective positions. In August 2015, the OII Administrative Law Judge issued a ruling that nine additional communications should have been reported in addition to a March 2013 communication that SCE had reported in February 2015. In December 2015, the CPUC issued a final decision that imposed a penalty of $16.74 million in connection with eight communications that the decision finds should have been reported and two violations of a CPUC ethical rule.

NRC Proceedings

As part of the NRC's review of the San Onofre outage and proceedings related to the possible restart of Unit 2, the NRC appointed an Augmented Inspection Team to review SCE's performance. In December 2013, the NRC finalized an Inspection Report in connection with the Augmented Inspection Team's review and SCE's response to an earlier NRC Confirmatory Action Letter. The NRC's report identified a "white" finding (low to moderate safety significance) for failing to ensure that MHI's modeling and analysis were adequate. In November 2014, the NRC closed the "white" finding, confirming that there were no additional issues identified that could impact SCE's ability to safely decommission San Onofre. The NRC also issued an Inspection Report to MHI containing a Notice of Nonconformance for its flawed computer modeling in the design of San Onofre's steam generators. On October 2, 2014, the NRC's Office of Inspector General ("OIG") published a report on the NRC's oversight of SCE's evaluation process for the RSGs, which was used to determine whether changes in the design of a component would require an amendment to the operating license of a nuclear power plant. The OIG determined that the NRC "missed opportunities" in connection with its 2009 inspection of SCE's evaluation process, and concluded that without further review of information concerning SCE's evaluation conclusions, there is no assurance that the NRC reached the correct conclusion in its 2009 inspection that San Onofre did not need a license amendment for its steam generator replacement.

In July 2015, the NRC issued a final decision regarding SCE's compliance with the license amendment regulatory process related to the RSGs, finding the issue to be moot, given the permanent cessation of operation of San Onofre. In March 2015, the NRC issued a lessons learned report in which it restated earlier NRC inspection findings that SCE properly concluded that the replacement steam generators at San Onofre did not require a formal license amendment prior to installation using a common NRC process for replacement components.

Certain anti-nuclear groups and individual members of Congress have alleged that SCE knew of deficiencies in the steam generators when they were installed or otherwise did not correctly follow NRC requirements for the design and installation of the replacement steam generators, all of which SCE has vigorously denied, and have called for investigations, including by the Department of Justice. SCE cannot predict when or whether ongoing proceedings by the NRC will be completed or whether inquiries by other government agencies concerning how the RSG project was conducted will be initiated or reopened.

NEIL Insurance Claims

San Onofre carries accidental property damage and carried accidental outage insurance issued by Nuclear Electric Insurance Limited ("NEIL"). Through August 30, 2014, the San Onofre owners had submitted approximately $433 million in claims (SCE's share of which is approximately $339 million) under the accidental outage insurance. The accidental outage insurance at San Onofre has been canceled prospectively as a result of the permanent retirement.

In October 2015, San Onofre owners reached an agreement with NEIL to resolve all insurance claims arising out of the failures of the San Onofre replacement steam generators for a total payment by NEIL of $400 million (SCE's share of which is approximately $313 million). According to the terms of the San Onofre OII Settlement Agreement, the settlement proceeds will be applied to reimburse the costs of pursuing the recovery and then allocated 95% to customers and 5% to SCE ($20 million pre-tax). SCE customers' portion of amounts recovered from NEIL has been distributed to SCE customers via a credit to SCE's ERRA account.

MHI Claims

SCE is also pursuing claims against Mitsubishi Heavy Industries, Ltd. and a related company ("MHI"), which designed and supplied the RSGs. MHI warranted the RSGs for an initial period of 20 years from acceptance and is contractually obligated to repair or replace defective items with dispatch and to pay specified damages for certain repairs. MHI's stated liability under the purchase agreement is limited to $138 million and excludes consequential damages, defined to include "the cost of replacement power;" however, limitations in the contract are subject to applicable exceptions both in the contract and under law. SCE has advised MHI that it believes one or more of such exceptions apply and that MHI's liability is not limited to $138 million. MHI has advised SCE that it disagrees. In October 2013, SCE sent MHI a formal request for binding arbitration under the auspices of the International Chamber of Commerce in accordance with the purchase contract seeking damages for all losses. In the request for arbitration, SCE alleges contract and tort claims and seeks at least $4 billion in damages on behalf of itself and its customers and in its capacity as Operating Agent for San Onofre. MHI has denied any liability and has asserted counterclaims for $41 million, for which SCE has denied any liability. Each of the other San Onofre owners sued MHI, alleging claims arising from MHI's supplying the faulty steam generators. These litigation claims have been stayed pending the arbitration. The other co-owners (SDG&E and Riverside) have been added as additional claimants in the arbitration. The arbitration is being conducted pursuant to a confidentiality order issued by the arbitration panel. Hearings are expected to occur in the first half of 2016 and a decision may be issued by year-end 2016.

SCE, on behalf of itself and the other San Onofre co-owners, has submitted seven invoices to MHI totaling $149 million for steam generator repair costs incurred through April 30, 2013. MHI paid the first invoice of $45 million, while reserving its right to challenge it and subsequently rejected a portion of the first invoice and has not paid further invoices, claiming further documentation is required, which SCE disputes. SCE recorded its share of the invoice paid (approximately $35 million) as a reduction of repair and inspection costs in 2012.

Under the San Onofre OII Settlement Agreement, recoveries from MHI (including amounts paid by MHI under the first invoice), if any, will first be applied to reimburse costs incurred in pursuing such recoveries, including litigation costs. To the extent SCE's share of recoveries from MHI exceed such costs, they will be allocated 50% to customers and 50% to SCE.

The first $282 million of SCE's customers' portion of such recoveries from MHI will be distributed to customers via a credit to a sub-account of SCE's Base Revenue Requirement Balancing Account ("BRRBA"), reducing revenue requirements from customers. Amounts in excess of the first $282 million distributable to SCE customers will reduce SCE's regulatory asset represented by the unamortized balance of investment in San Onofre base plant, reducing the revenue requirement needed to amortize such investment. The amortization period, however, will be unaffected. Any additional amounts received after the regulatory asset is recovered will be applied to the BRRBA.

The San Onofre OII Settlement Agreement provides the utilities with the discretion to resolve the NEIL and MHI disputes without CPUC approval or review, but the utilities are obligated to use their best efforts to inform the CPUC of any settlement or other resolution of these disputes to the extent this is possible without compromising any aspect of the resolution. SCE and SDG&E have also agreed to allow the CPUC to review the documentation of any final resolution of the NEIL and MHI disputes and the litigation costs incurred in pursuing claims against NEIL and MHI to ensure they are not exorbitant in relation to the recovery obtained. There is no assurance that there will be any recovery from MHI or, if there is a recovery, that it will equal or exceed the litigation costs incurred to pursue the recovery.

Wildfire Insurance

Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Prolonged drought conditions in California have also increased the risk of severe wildfire events. On June 1, 2015, Edison International renewed its liability insurance coverage, which included coverage for SCE's wildfire liabilities up to a $610 million limit (with a self-insured retention of $10 million per wildfire occurrence). Various coverage limitations within the policies that make up this insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy period (June 1, 2015 to May 31, 2016). SCE also has additional coverage for certain wildfire liabilities of $390 million, which applies when total covered wildfire claims exceed $610 million, through June 14, 2016. SCE may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.

Spent Nuclear Fuel

Under federal law, the Department of Energy ("DOE") is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE has not met its contractual obligation to accept of spent nuclear fuel. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. Currently, both San Onofre and Palo Verde have interim storage for spent nuclear fuel on site sufficient for their current license period.

In June 2010, the United States Court of Federal Claims issued a decision granting SCE and the San Onofre co-owners damages of approximately $142 million (SCE share $112 million) to recover costs incurred through December 31, 2005 for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. SCE received payment from the federal government in the amount of the damage award. SCE, as operating agent, filed a lawsuit on behalf of the San Onofre owners against the DOE in the Court of Federal Claims seeking damages of approximately $182 million for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel for the period from January 1, 2006 to December 31, 2013. Additional legal action would be necessary to recover damages incurred after December 31, 2013. All damages recovered by SCE are subject to CPUC review as to how these amounts would be distributed among customers, shareholders, or to offset fuel decommissioning or storage costs.

Item 3.

N/A

Item 4.

These accounts are used where applicable. The balance for unamortized loss on reacquired debt (account number 189.XXX) at December 31, 2015 was approximately $201 million. There is no unamortized gain (account number 257.XXX) recorded at December 31, 2015.

Item 5.

The CPUC regulates SCE's capital structure which limits the dividends it may pay Edison International. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above 48% on a 13-month weighted average basis. At December 31, 2015, SCE's 13-month weighted-average common equity component of total capitalization was 49.9% and the maximum additional dividend that SCE could pay to Edison International under this limitation was approximately $441 million. The remaining $13.2 billion of SCE's net assets are restricted.

Item 6.

See responses to Items 1 and 2 above.

Item 7.

See responses to Items 1 and 2 above.

Item 8.

See responses to Items 1 and 2 above.

Item 9.

See responses to Items 1 and 2 above.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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				(10,924,608)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(18,775,000)
3	Preceding Quarter/Year to Date Changes in Fair Value				1,533,560
4	Total (lines 2 and 3)				(17,241,440)
5	Balance of Account 219 at End of Preceding Quarter/Year				(28,166,048)
6	Balance of Account 219 at Beginning of Current Year				(28,166,048)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				5,830,628
8	Current Quarter/Year to Date Changes in Fair Value				202,564
9	Total (lines 7 and 8)				6,033,192
10	Balance of Account 219 at End of Current Quarter/Year				(22,132,856)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [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			(10,924,608)		
2			(18,775,000)		
3			1,533,560		
4			(17,241,440)	1,564,685,057	1,547,443,617
5			(28,166,048)		
6			(28,166,048)		
7			5,830,628		
8			202,564		
9			6,033,192	1,111,055,146	1,117,088,338
10			(22,132,856)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)	37,188,663,144	37,155,069,383
4	Property Under Capital Leases	51,847,495	51,847,495
5	Plant Purchased or Sold		
6	Completed Construction not Classified	4,401,445,617	4,401,445,617
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	41,641,956,256	41,608,362,495
9	Leased to Others		
10	Held for Future Use	16,261,747	16,261,747
11	Construction Work in Progress	3,218,015,337	3,203,958,208
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	44,876,233,340	44,828,582,450
14	Accum Prov for Depr, Amort, & Depl	12,841,098,825	12,818,426,283
15	Net Utility Plant (13 less 14)	32,035,134,515	32,010,156,167
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	11,894,107,945	11,871,435,403
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	946,990,880	946,990,880
22	Total In Service (18 thru 21)	12,841,098,825	12,818,426,283
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	12,841,098,825	12,818,426,283

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

Gas (d)	Other (Specify) Water (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
5,142,307	27,335,471			1,115,983	3
					4
					5
					6
					7
5,142,307	27,335,471			1,115,983	8
					9
					10
2,094,872	7,176,977			4,785,280	11
					12
7,237,179	34,512,448			5,901,263	13
2,151,312	19,956,338			564,892	14
5,085,867	14,556,110			5,336,371	15
					16
					17
2,151,312	19,956,338			564,892	18
					19
					20
					21
2,151,312	19,956,338			564,892	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
2,151,312	19,956,338			564,892	33

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

Includes $44 million of asset related to an SCE power contract that was classified as a capital lease in 2014. During 2015, the contract was amended, which resulted in a reduction in the lease obligations and asset by $147 million in 2015. The amended contract contained terms that no longer met the lease criteria.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	53,747,473	42,444,171
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	53,747,473	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	191,001,509	38,181,281
10	SUBTOTAL (Total 8 & 9)	191,001,509	
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)	114,144,642	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	130,604,340	
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
	38,196,983	57,994,661	3
			4
			5
		57,994,661	6
			7
			8
	90,278,918	138,903,872	9
		138,903,872	10
			11
			12
-41,714,539	90,278,918	65,580,263	13
		131,318,270	14
			15
			16
			17
			18
			19
			20
			21
			22

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

Transfer of costs from fuel in process to fuel in the reactor and write off. (Account 120.1 - $38,181,281 and Account 120.1 - $15,702). SONGS nuclear fuel activities are not included in the data above since the balances were transferred to regulatory assets in 2014 resulting from the shutdown of SONGS.

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

Retired fully amortized batches. (Account 120.3 and Account 120.5 - $90,278,918). SONGS nuclear fuel activities are not included in the data above since the balances were transferred to regulatory assets in 2014 resulting from the shutdown of SONGS.

Schedule Page: 202 Line No.: 13 Column: e

Retired fully amortized batches. (Account 120.3 and Account 120.5 - $90,278,918). SONGS nuclear fuel activities are not included in the data above since the balances were transferred to regulatory assets in 2014 resulting from the shutdown of SONGS.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	2,847,931	100,309
3	(302) Franchises and Consents	131,642,769	2,224,433
4	(303) Miscellaneous Intangible Plant	1,742,752,456	98,214,045
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,877,243,156	100,538,787
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	811,918	
9	(311) Structures and Improvements	722,796	
10	(312) Boiler Plant Equipment	1,059,642	
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment	3,778	43,828
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,598,134	43,828
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,745,227	189,341
19	(321) Structures and Improvements	583,820,314	15,303,840
20	(322) Reactor Plant Equipment	703,583,013	15,761,510
21	(323) Turbogenerator Units	251,254,745	4,854,095
22	(324) Accessory Electric Equipment	182,845,720	20,475,790
23	(325) Misc. Power Plant Equipment	110,425,691	-621,264
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,833,674,710	55,963,312
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	5,089,919	
28	(331) Structures and Improvements	205,566,317	1,474,020
29	(332) Reservoirs, Dams, and Waterways	566,127,053	4,387,811
30	(333) Water Wheels, Turbines, and Generators	173,651,479	2,951,967
31	(334) Accessory Electric Equipment	205,593,041	2,948,932
32	(335) Misc. Power PLant Equipment	12,115,831	56,643
33	(336) Roads, Railroads, and Bridges	19,081,132	91,770
34	(337) Asset Retirement Costs for Hydraulic Production	8,086,942	-172,275
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,195,311,714	11,738,868
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,745,315	
38	(341) Structures and Improvements	84,229,911	343,281
39	(342) Fuel Holders, Products, and Accessories	11,792,981	4,731,243
40	(343) Prime Movers	1,107,036,554	-2,431,750
41	(344) Generators	123,662,158	1,811,182
42	(345) Accessory Electric Equipment	182,474,606	79,456
43	(346) Misc. Power Plant Equipment	10,256,745	75,411,782
44	(347) Asset Retirement Costs for Other Production	38,198,356	-156,895
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,561,396,626	79,788,299
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,592,981,184	147,534,307

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	320,113,711	8,331,585
49	(352) Structures and Improvements	628,958,105	54,786,401
50	(353) Station Equipment	4,996,027,821	287,667,256
51	(354) Towers and Fixtures	1,883,502,324	377,241,683
52	(355) Poles and Fixtures	838,670,098	179,416,872
53	(356) Overhead Conductors and Devices	1,275,427,830	208,949,509
54	(357) Underground Conduit	56,304,666	-1,392,030
55	(358) Underground Conductors and Devices	248,470,086	22,306,925
56	(359) Roads and Trails	86,695,550	107,382,662
57	(359.1) Asset Retirement Costs for Transmission Plant	11,896,884	-1,735,617
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	10,346,067,075	1,242,955,246
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	107,597,922	7,670,516
61	(361) Structures and Improvements	523,812,732	65,133,327
62	(362) Station Equipment	2,063,610,308	204,493,400
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	2,050,931,742	430,697,250
65	(365) Overhead Conductors and Devices	1,337,389,946	106,937,877
66	(366) Underground Conduit	1,629,943,644	191,700,938
67	(367) Underground Conductors and Devices	5,140,891,513	457,113,760
68	(368) Line Transformers	3,317,285,997	242,180,245
69	(369) Services	1,254,929,720	48,081,544
70	(370) Meters	982,501,960	14,324,462
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	835,020,556	54,209,308
74	(374) Asset Retirement Costs for Distribution Plant	12,129,938	-339,663
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	19,256,045,978	1,822,202,964
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	29,016,212	16,680
87	(390) Structures and Improvements	911,772,756	46,598,023
88	(391) Office Furniture and Equipment	735,104,262	52,716,935
89	(392) Transportation Equipment	12,200,075	169,394
90	(393) Stores Equipment	10,242,183	2,715,167
91	(394) Tools, Shop and Garage Equipment	86,872,300	7,048,235
92	(395) Laboratory Equipment	92,451,440	12,406,201
93	(396) Power Operated Equipment	712,432	-1,015
94	(397) Communication Equipment	814,287,958	103,843,620
95	(398) Miscellaneous Equipment	18,967,741	10,291,465
96	SUBTOTAL (Enter Total of lines 86 thru 95)	2,711,627,359	235,804,705
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	2,616,185	-1,261,854
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	2,714,243,544	234,542,851
100	TOTAL (Accounts 101 and 106)	38,786,580,937	3,547,774,155
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)	38,786,580,937	3,547,774,155

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
			2,948,240		2
			133,867,202		3
379,698,543		-128,956	1,461,139,002		4
379,698,543		-128,956	1,597,954,444		5
					6
					7
			811,918		8
			722,796		9
			1,059,642		10
					11
					12
					13
			47,606		14
					15
			2,641,962		16
					17
			1,934,568		18
62,289			599,061,865		19
746,352			718,598,171		20
2,370,752			253,738,088		21
8,582			203,312,928		22
25,676		128,956	109,907,707		23
					24
3,213,651		128,956	1,886,553,327		25
					26
		6	5,089,925		27
92,247		529	206,948,619		28
173,116			570,341,748		29
3,578,454			173,024,992		30
171,507			208,370,466		31
2,129		315,139	12,485,484		32
			19,172,902		33
			7,914,667		34
4,017,453		315,674	1,203,348,803		35
					36
			3,745,315		37
			84,573,192		38
			16,524,224		39
1,159,888		-1,517	1,103,443,399		40
			125,473,340		41
			182,554,062		42
		-401,874	85,266,653		43
			38,041,461		44
1,159,888		-403,391	1,639,621,646		45
8,390,992		41,239	4,732,165,738		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
14,832		263	328,430,727		48
2,270,625		5,353,522	686,827,403		49
48,281,976		12,298,705	5,247,711,806		50
771,182			2,259,972,825		51
9,485,039		-34,572	1,008,567,359		52
2,269,714			1,482,107,625		53
23,257		6,197,683	61,087,062		54
2,164,688			268,612,323		55
60,171			194,018,041		56
			10,161,267		57
65,341,484		23,815,601	11,547,496,438		58
					59
8		3,638	115,272,068		60
6,886,558		-5,353,522	576,705,979		61
11,534,474		-12,298,705	2,244,270,529		62
					63
18,277,209		34,572	2,463,386,355		64
11,336,716		-3,797	1,432,987,310		65
4,058,183		-5,725,791	1,811,860,608		66
49,133,726		-467,221	5,548,404,326		67
50,383,880		-443,067	3,508,639,295		68
1,599,083		-4,774	1,301,407,407		69
16,134,329		443,067	981,135,160		70
					71
					72
17,146,243			872,083,621		73
			11,790,275		74
186,490,409		-23,815,600	20,867,942,933		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-889	29,032,003		86
11,258,612		-15	947,112,152		87
89,787,412			698,033,785		88
957,023			11,412,446		89
282,627			12,674,723		90
3,983,127			89,937,408		91
4,362,263			100,495,378		92
			711,417		93
26,823,795		-330,215	890,977,568		94
133,292		88,320	29,214,234		95
137,588,151		-242,799	2,809,601,114		96
		2	2		97
			1,354,331		98
137,588,151		-242,797	2,810,955,447		99
777,509,579		-330,513	41,556,515,000		100
					101
					102
					103
777,509,579		-330,513	41,556,515,000		104

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	NONE.				
2					
3					
4					
5					
6					
7					
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44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	350 - Land and Land Rights:			
3				
4				
5	Under $250,000 (4 Properties)	Various	Various	210,090
6				
7				
8				
9	360 - Land and Land Rights:			
10				
11				
12	Under $250,000 (3 Properties)	Various	Various	270,459
13				
14				
15				
16	360 - Land and Land Rights:			
17				
18				
19	Over $250,000 (1 Property)	2011	2016	15,781,198
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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45				
46				
47	Total			16,261,747

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	WORK ORDERS OVER $1,000,000	
2	TDBU GIS - Phase 2	52,834,233
3	C-RAS:Capital:Master Workorder	50,654,718
4	FIP-West of Devers Upgrade Project:	48,236,877
5	PIV2 - New Metro East Office Bldg -	32,156,321
6	SC: MP NATURAL 66/12 NEW CUST SUB P	30,152,259
7	Commodity Management Platform Progr	28,293,628
8	8065-5001--Alberhill: Licensing Pha	27,811,560
9	La Fresa Sub (Phase 2): Install ne	26,821,750
10	Natural Sub: Phase 2- Construct a n	26,078,050
11	5063-8201--JULIAN HINDS: INSTALL NE	25,549,647
12	CCS Phase3-Rel 1 Core&Phasor Integr	25,515,018
13	HANA Software	24,847,948
14	SC JS/KH/JH R/R TOWERS W/66-TSP'S,	22,636,307
15	Saugus Sub: Install a fourth 280 MV	22,474,716
16	SC JS 4605-2104--MOORPARK-NEWBURY 6	22,303,826
17	I:Downs Sub: Install new 6 position	22,159,951
18	Water Valley: Construct new Water V	20,675,444
19	Enterprise Compliance Mgmt Syst - M	20,231,121
20	DH J.Shumaker/C.Hotta R/R 9 TRANS	19,456,631
21	VA-4950-0353--IVYGLEN: BRING IN SEC	19,332,481
22	1810-6128 WNU-00500	18,301,949
23	SanOnofre220kVSwitchyardSegregate(S	17,753,155
24	DMS Phase 2	17,409,326
25	GEOGRAPHICAL INFORMATION SYS - GIS	17,341,142
26	TOT223 Devers-Install 4 reactor ban	16,985,457
27	SC PG GCC (ALHAMBRA) VIDEO WALL (LA	16,913,868
28	ACQ07186379 Lake Elsinore=Alberhill	15,781,292
29	CS - GO Parking Lot	15,689,178
30	FIP-Mira Loma Sub: Install Relays	15,237,172
31	ACQ/Circle City Substation	14,642,507
32	3064 0376 GENERATION AUTOMATION INS	14,563,062
33	SCE.com Strategic Upgrade - Wasabi	14,364,491
34	8191-5001--Falcon Ridge: Licensing	14,312,830
35	Bailey Sub: Upgrade protection as r	13,094,837
36	Valley 'A/B' 500/115 - Install 115k	12,994,822
37	FL - Geomembrane Liner	12,987,965
38	Devers: Pos. 1 - Relocate the Coach	12,328,632
39	PoLAR - Phase II & Phase III Master	12,263,019
40	RI-Vista Substation Facility-Instal	12,097,316
41	EHSync Project	12,020,338
42	Eldorado: Install (2) 500 kV CBs, (	11,826,739
43	TOTAL	3,203,958,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	4585-9000--DEVERS-PALO VERDE: PE &	11,316,580
2	Mesa Substation: Upgrade Mesa from	11,094,954
3	VA-CONSTRUCT APPROXIMATELY 12.5MILE	10,294,767
4	I:Lugo: Inst 500kV double breakers	10,290,287
5	Vestal: Equip 230 KV A-Bank positio	10,166,290
6	ACQ:CHUG - TRTP-Segment 8	9,854,208
7	Lugo:Instl ballistic barrier(CIP-1	9,776,048
8	SC YW TLRR (22) 4601344 Pardee-Vinc	9,727,852
9	Leatherneck: Engineer, design, cons	9,657,415
10	Serrano:Instl ballistic barrier(CI	9,516,976
11	DEFERRED MPR - Replace HB Valve	9,510,416
12	Alamitos Sub: Install a new MEER.	9,461,525
13	Advanced Access Controls-Perim. Def	9,399,750
14	FIP-Bluff Minor Add to 900248417	9,220,094
15	VA- SUB CONTROL ROOM REMODEL	9,212,788
16	PVCER - Nucl Admin & Tech Manual Re	8,950,216
17	Redlands SC - Facility Upgrade - CA	8,840,974
18	Banducci: Construct new 66/12 kV su	8,514,861
19	VA-4950-0435--ET-SE-SANJACIN* VALLE	8,422,204
20	Eldorado: Replace No. 3AA Bank 500/	8,357,765
21	8116-5001--Circle City (formerly Ho	8,168,849
22	ARIBA P2P Enhancement	8,063,106
23	4570-8206--ET-01738*DEVERS-CARODEAN	8,033,534
24	Enhance Interior Defense - Master W	7,712,176
25	AL Eldorado: Install (3) 220 kV CBs	7,601,964
26	1867-9999-PV PREPAID RECORDED CAPIT	7,380,794
27	Villa Park: Equip the existing No.	7,216,696
28	FIP-West Transition Station: ML-V 5	7,119,902
29	PV2PM - Dig Upgrd Generrex Unit 2	6,987,652
30	RI Devers Substation New Control Bu	6,977,201
31	Leatherneck Sub: Licensing Phase -	6,884,977
32	FIP-East Transition Station: ML-V 5	6,883,509
33	FIP - Chino Hills Related OH Line W	6,837,607
34	Ridgecrest SC - Facility Upgrade -	6,794,992
35	Santiago:Install 2 synchronous cond	6,699,748
36	La Fresa 'B' Sub: Replace (25) 66kV	6,689,603
37	Pardee Sub: Phase 1: Install 220 kV	6,687,171
38	RULE 20C-CONVERT OH 66KV TO UG PROJ	6,619,863
39	FIP-Whirlwind Install 500/220kV AA	6,558,587
40	DSP DSPPIF# 326509: NEW CIRCUIT, GR	6,455,907
41	Phase 1: Chino Sub: Install 40 new	6,336,864
42	Windhub (IF): Install One GE L90 li	6,293,302
43	TOTAL	3,203,958,208

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	SC PG AGCC (IRVINE) VIDEO WALL (LAR	6,219,160
2	Santiago Install 2 66/33 Xfrmr 1N&1	6,185,685
3	SYLMAR/LADWP JOB # B1220 SYLMAR -	6,069,758
4	5026-8202--EL SEGUNDO: CONNECT UNIT	6,010,563
5	2015 C&C - Data Protection VLTG	5,904,943
6	BC4 - Relicensing	5,792,328
7	Colton: Install SA2.	5,752,551
8	Server Sub: Construct a new 56 MVA	5,683,453
9	MDMS Stabilization Project	5,644,175
10	Pier: Design and construct a new 28	5,555,785
11	TLRR PRI A-2 4702585 (1660)	5,506,832
12	Enhanced Alerts & Notifications - R	5,412,656
13	Tax Repairs - Master Work Order	5,406,592
14	SC: MP NATURAL 66/12 NEW CUST SUB P	5,391,932
15	Pier J: Construct new 28 MVA, 66-12	5,264,875
16	NEB completed 2015/03/20	5,251,587
17	CAP ONRAMP CABLE ET-00817	5,220,507
18	5123-8201--WEYMOUTH SUB: INSTALL A	5,211,029
19	C&C Data Protection - DP-003	5,039,187
20	T&D Supply Chain Redesign	4,977,137
21	Process 66/12kV Substation: Install	4,925,994
22	PORT OF LONG BEACH RELOCATION - PHA	4,814,396
23	Saugus Sub (Ph II): Upgrade sub to	4,796,932
24	CAP ONRAMP CABLE ET-01009 BOWL-LON	4,773,033
25	VI-Lugo Sub Install New Control Bui	4,756,448
26	Declez: Install SA2.	4,745,810
27	Kramer(IF):Int.FacilitiesforWaterVa	4,741,977
28	RI- 4505-3141--DEL ROSA-HIGHLAND 66	4,689,266
29	Orange Sub: Cnstrct 12kV wrap arnd	4,678,568
30	ECS - Data Protection - S/W & PS	4,653,978
31	GO1 - Garage Upgrades CAP	4,596,118
32	WRF - WRF 7th Clarifier Train	4,595,994
33	Springville Substation: Replace the	4,594,602
34	Nietos Sub: Reconfigure Nietos Subs	4,587,441
35	Mira Loma Sub: Install On-Line DGA	4,586,662
36	5026-5015 EL SEGUNDO: ENGINEERING,	4,572,781
37	Royal:Upgrade 66kV relays <(>&<)> e	4,547,632
38	DH DB LA FRESA A-SYSTEM PROJECT-PIN	4,538,459
39	Cool Water Sub: Replace 4-220kV CB;	4,520,180
40	BISHOP SC - Facility Modernization-	4,518,516
41	Victor:Loop Kramer-Lugo line into V	4,466,675
42	HL-Dam 1&2 Replace Controls	4,445,062
43	TOTAL	3,203,958,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	CMS Package 2 Master	4,415,499
2	Safari: New 33/12 station	4,412,415
3	C&C-Perimeter Def. Appliances & SW	4,376,782
4	5054-5093--VINCENT: INSTALL ONLINE	4,333,655
5	2015 C&C - Perimeter Defense BC	4,240,607
6	I5155-8201--DIEMER: INSTALL A NEW 1	4,237,397
7	Eldorado: Replace No 4AA Bank 500/2	4,222,963
8	SYLMAR/LADWP - AC/DC Filter Replace	4,072,906
9	DH L.Harvey/C.Hotta CAP ONRAMP CABL	4,055,690
10	BUILD NEW VICTOR-AQUADUCT 115KV PI	3,999,182
11	Shaver Lake SC - Expansion Project	3,917,420
12	8073-5007--IVYGLEN SUB: PRELIMINARY	3,809,518
13	BC1 - Install Wastewater Diversion	3,791,555
14	DSP DSP529002 MENDOCINO 12KV % FAIR	3,778,924
15	DH KC Converted UG 20A SAP WO 4405-	3,768,350
16	5189-8201--GRAND CROSSING: ENGINEER	3,759,036
17	MENIFEE Offsites Phase 2 - CAPITAL	3,755,192
18	SA 4805-8209 Constr.7000ft.Brea-Alp	3,728,215
19	1320-0604-MOHAVE-'C'AQUIFER STUDY,	3,727,884
20	RULE 20B HERITAGE FIELDS -	3,702,656
21	RELO BASHULA-LEMON/ORANGETHORPE	3,644,929
22	Storage - Capacity Growth ADC	3,624,836
23	TLRR PRI A-2 4705312 (58)	3,611,587
24	BSH-Replace Water Systems and Tanks	3,569,167
25	El Nido:Install 2 GE N60 rel. CRAS-	3,563,144
26	NCV5_CS-MRA LOMA SUB	3,559,100
27	INFRASTRUCTURE REPLACEMENT (CONDUCT	3,545,489
28	TBD - 63	3,478,500
29	LIDAR PRI A-1: 4401379 (2)	3,470,012
30	SolarStar2-Whirlwind 220kVGenTieLin	3,468,013
31	Ship Sub: Construct one (1) low pro	3,461,275
32	DH LHarvey/CHotta LA FRESA A-SYSTEM	3,420,601
33	FIP-WOD 220 kV Trans Line Installat	3,396,714
34	CAP ONRAMP CABLE ET-00809 HINSON-L	3,389,468
35	OMS V6 Refresh - Tech Refresh Maste	3,344,047
36	C&C Perimeter Defense - PD-003	3,334,809
37	FIP-TRTP Segment 3B: Highwind-Windh	3,330,330
38	SC PG-ORANGE COUNTY SWITCHING CENTE	3,319,861
39	Clementine: Construct new 115kV sta	3,315,792
40	CO Orozco RULE20B INSTALL CNC ENG-C	3,298,534
41	EPP Phase 3 - Master WO	3,256,805
42	Cool Water-Kramer No.1: Loop-in to	3,231,580
43	TOTAL	3,203,958,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	RELOCATE FACILITIES RELOCATE FACILI	3,206,267
2	Devers:Instl ballistic barrier(CIP	3,204,300
3	C&C Perimeter Defense - PD-004	3,198,923
4	5057-5001--Wildlife: Engineer, desi	3,190,762
5	Nugget Substation: Replace No.1 and	3,183,052
6	BC1 - Relicensing	3,119,552
7	I: TRTP 1: Environmental Mitigation	3,102,765
8	5067-5033--DEVERS: INSTALL ONLINE D	3,095,677
9	CITRIX VDI Capacity Increase	3,090,114
10	Highwind-Jawbone 220kV Gen Tie (Ini	2,989,933
11	Kernville SC - Facility Upgrade - C	2,984,074
12	DSP DSPSAP 901238303, AT /I0702661,	2,974,225
13	EME-Walnut 230kV T/L: Procure and c	2,955,915
14	Walnut/CFF Install two new CBs, one	2,947,784
15	RELOCATE FACILITIES	2,939,849
16	DSP DSPPIF-522002 NEW DSP CIRCUIT B	2,931,387
17	SC PG-MIRA LOMA SUBSTATION CONTROL	2,924,421
18	Octol 66/12 kV- Install 2-28 MVA Ba	2,921,375
19	PV1ER - Spray Pond Concrete Replace	2,902,973
20	Lugo:New control room capital suppo	2,894,597
21	BC2 - Relicensing	2,885,130
22	BC2A - Relicensing	2,875,263
23	RULE 20A - UG INSTALL RULE 20A - UG	2,862,916
24	INSTALL TOWER TO RAISE LINES PALO V	2,861,795
25	Ivanpah(IF):Term.Ivanpah-DesertStat	2,861,721
26	San Fernando: Phase 1-Install a new	2,859,514
27	Chevgen Substation: Modify existing	2,854,315
28	GMS Platform Upgrade-Master WO for	2,853,157
29	INFRASTRUCTURE REPLACEMENT (CONDUCT	2,847,395
30	FIP-I: Jasper:new 220kV Interconnec	2,844,116
31	Walnut: Equip banks w/ circuit brea	2,840,019
32	BC3 - Relicensing	2,839,037
33	MPPH - Relicensing	2,823,647
34	BC8 - Relicensing	2,801,731
35	NEB True Up Completed - MR	2,779,535
36	EPS - Relicensing	2,757,748
37	2014 Perimiter Tools	2,719,901
38	T&D SmartScreen Project - MASTER	2,717,397
39	4205-4904--ET-06609* RECTOR-GOSHEN	2,708,725
40	DM Refresh - Master WO	2,701,768
41	SC PG-LIGHTHIPE SUBSTATION & LIGHTH	2,697,328
42	2015 C&C Interior Protection - Cyln	2,653,396
43	TOTAL	3,203,958,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	5056-5071--MOORPARK: INSTALL NEW 66	2,647,764
2	2015 C&C Interior Protection - FRSC	2,625,252
3	Chino: equip 1A pos with CBs	2,615,549
4	SCE.com License Purchase	2,601,096
5	Additional Desalination System Proj	2,594,923
6	NCV5_CS-MESA	2,577,877
7	Fairview: Install line position w/	2,555,888
8	ADDED FACILITIES	2,551,538
9	8564-5001--Presidential Sub: Licens	2,542,095
10	OCTA 20B_TUSTIN&ROSE UNDERGROUND CO	2,505,856
11	Kimball: Install 2 line position &	2,492,497
12	RI Mira Loma Substation-New Control	2,488,793
13	46 STRM 2015-07-30T23:00:00Z	2,488,189
14	DH LH/A.Delgado 4405-0365 **Conve	2,485,713
15	DsrtStrWhrlwnd220kV GenTie Install	2,476,418
16	RELOCATE FACILITIES	2,471,047
17	NCV5_CS-CONTROL SUB	2,436,823
18	RULE 20A - UG INSTALL	2,431,159
19	Thrive Sub: Engineer and construct	2,429,583
20	EPH - Timberwine 12KV Substation	2,396,411
21	BSH-Rebuild Lee Vining Substation	2,385,001
22	BC3-U3 Rewind Field Poles	2,375,281
23	77 6-21-10 6777-7119-77188	2,364,898
24	Whirlwind(NU): Install 220kV CBs, R	2,362,512
25	5137-8201--CYBER SUB: INSTALL A NEW	2,327,002
26	PPH - Replace Main Bank & SL&P	2,324,499
27	NCV5_CS-LIGHTHIPE SUB	2,286,183
28	O365 - Infrastructure (IOC)	2,283,259
29	SC KH/JH R/R 28 TOWERS W/28-TSP SEG	2,257,474
30	Solar Star 1-Whirlwind 220 kV Gener	2,226,212
31	LED2-13I-LA FRESA	2,210,163
32	ANGELD-15I-MRP PHASE 2-AlhambraComm	2,209,160
33	NCV5_CS-OC SWITCH CTR	2,181,261
34	NCV5_CS-MOORPARK SUB	2,167,245
35	O365 - Infrastructure (ADC)	2,155,873
36	RULE 20A - UG INSTALL RULE 20A - UG	2,152,002
37	Vincent: Add 220kV Sectin Brkrs po	2,116,044
38	CO Manuel Transferred 1-85ft.H4 on	2,100,137
39	RE RECTOR TRANSMISSION LAYDOWN YARD	2,082,769
40	Dalton: Replace (21)DPU & (2)TPU Re	2,080,456
41	NCV5_CS-GCC	2,079,961
42	Etiwanda Sub: Rplc (15) 66 kV CBs	2,072,316
43	TOTAL	3,203,958,208

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)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	La Fresa Substation: Replace No. 2A	2,061,610
2	NCV5_CS-ELDORADO SUB	2,058,919
3	Victor: Install necessary phasor me	2,056,616
4	Storage - Capacity Growth IOC	2,039,864
5	VA-VALLEY SUB INSTALL VIDEO WALL/LA	2,036,446
6	Kramer: Install necessary phasor me	2,031,780
7	NCV5_CS-VENTURA SWITCH CTR	2,021,664
8	SC: RC Saugus-Fillmore No.1 & No.2,	2,012,382
9	Grid Data Center Program	2,008,593
10	ANGELD-14I-MRP PH5 DSR IVD-RanchoVi	2,003,374
11	RI-4505-4929--ALDER-DECLEZ 66KV: BU	1,982,090
12	La Cienega :Install 2 GE N60 rel. C	1,967,646
13	RELOCATE FACILITIES TD715437(#1150)	1,961,413
14	Springville Sub: Redesign high side	1,947,687
15	RULE 20A - UG INSTALL	1,946,872
16	SC PG-RECTOR SUBSTATION CONTROL ROO	1,941,165
17	5557-5018--Newbury: Install one (1)	1,940,805
18	5080-5046--SERRANO: INSTALL ONLINE	1,940,429
19	PVCFK - Mitigating Strateg (FLEX) &	1,937,954
20	C&C Perimeter Defense - PD-001	1,922,034
21	RELOCATE FACILITIES RELOCATE FACILI	1,900,021
22	NCV5_CS-IOC ESM	1,897,853
23	SC PG-EL NIDO SUBSTATION CONTROL RO	1,895,510
24	Eldorado: Install (2) 220kV CBs, (4	1,883,617
25	Yucca- Replace No. 2 E&W 115/12kV B	1,876,600
26	Security Access Control Fire Prot.	1,868,117
27	T&D Miscellaneous Equipment - Capit	1,867,188
28	RE CONSTRUCTION OF NEW CONTROL ROO	1,859,492
29	Lugo: Replace emergency generator	1,858,437
30	Colton Substation: Replace No. 1 an	1,854,721
31	RI DEVERS SUB CONTROL ROOM - INSTAL	1,854,042
32	5070-5005--VALLEY SUB: EQUIP A NEW	1,853,185
33	DEFERRED KR - Borel-Rebuild Canals/	1,848,005
34	Telegraph Substation: Replace (16)	1,838,147
35	Neenach (IF): Install equipment for	1,834,038
36	ACQ Mesa 500kV Substation	1,833,266
37	Porterville:Replace 1N&1S&2 Banks66	1,832,669
38	Yucca: Install bus tie pos & 1 CB w	1,820,859
39	C&C Interior Defense - ID-004	1,817,072
40	DH R.Morgan/A.Delgado RULE20B INST	1,809,782
41	PVCFK - Seismic Hazards Validation	1,804,439
42	NCV5_CS-DEVERS SUB	1,800,057
43	TOTAL	3,203,958,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	RELOCATE FACILITIES-CALTRANS HIGHWA	1,792,257
2	WANGL-13I-Eldorado5AABank-EldoradoS	1,789,395
3	Moorpark: Replace 150 caps, PTs and	1,785,842
4	Ventura SC - Paving (Phase 2)	1,774,217
5	2015 C&C - Perimeter Defense (NS)	1,771,343
6	WDT213 LOOP THE BOTTLE-GARNET-WINDF	1,760,154
7	Neenach Substation (POS Reliability	1,753,744
8	PV1PM - Rad Monitoring System Monit	1,752,372
9	2015 - Microsoft ELA True Up	1,751,402
10	2014 C&C - HW- Perimeter - DNS	1,741,668
11	Integrated Budget Planning	1,726,931
12	VISTA SUB INSTALL VIDEO WALL/LARGE	1,719,284
13	Devers: Install EMS	1,672,865
14	SC PG-VINCENT SUBSTATION CONTROL RO	1,672,036
15	SC PG-LUGO SUBSTATION CONTROL ROOM:	1,670,722
16	Distributables 2015	1,667,322
17	2015 C&C - Perimeter Defense GS	1,665,413
18	Vista: Install EMS	1,660,768
19	SC AC EL NIDO SUB Phase 2/Cont	1,643,501
20	Whirlwind Substation Interconnectio	1,641,967
21	SC PG-MESA SUBSTATION CONTROL ROOM:	1,632,956
22	Zanja Substation: Replace No. 1 Ban	1,630,640
23	CO YONG-MESA-RUSH NO.3 RECABLE PIN	1,628,000
24	NEB Completed 07/18/2015	1,612,439
25	LED2-12I-CRAS:Alhambra-AlhambraCS	1,605,481
26	CO-SANTA ANA BUILDING A (6029)	1,588,360
27	SC: JS RULE 20B GOLETA HOLLISTER-GL	1,586,922
28	U_HBGS-WAVE FO (03200) PROPOSED *DZ	1,584,790
29	ColoradoRiv(IF) install dead-end st	1,583,958
30	Eldorado: 3AA and 4AA Fire Mitigati	1,581,522
31	KR1 Replace Forebay Walkway	1,575,165
32	Eldorado-Ivanpah #1(NU): Loop into	1,571,820
33	WANGL-13I-SilverStateSouth-PrimmSub	1,568,025
34	OASIS IF Install Position	1,563,829
35	WRF - Sewage Treatment Plant Replac	1,561,997
36	46 STRM 2015-07-15T22:07:00Z	1,557,825
37	BC8 - High pressure piping	1,554,671
38	Lugo: Install EMS	1,542,223
39	8012-5025--MIRAGE: INSTALL ONLINE D	1,541,895
40	Nerc CIP V.5 - SSM Prog- CSN-T/Alha	1,538,467
41	Eldorado Sub - Add Waterline - CAPI	1,534,800
42	RELOCATE FACILITIES RELOCATE FACILI	1,528,603
43	TOTAL	3,203,958,208

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	RELOCATE FACILITIES-BILLING TD71553	1,528,057
2	5422-5001--PURIFY SUB: INSTALL A NE	1,524,790
3	SA 4805-5935 Rule 20B Irvine Co./ K	1,514,541
4	NCV5_CS-RECTOR	1,513,976
5	NEB True Up Completed - MR	1,511,722
6	SC PG-VENTURA SWITCHING CENTER CONT	1,511,566
7	ACQ: CPUC - Lakeview Substation, RO	1,497,597
8	IMEP5 Fall 2015	1,486,816
9	Goleta: El Nino Preparation	1,482,644
10	Carpinteria:Add 66KV line pos 1-CB	1,482,469
11	Center: Remove No. 1C and 2C Banks	1,477,827
12	I5 WIDENING SEG 5 PROJECT ID 114	1,477,557
13	AR Remittance Processing Equipment	1,470,234
14	ADDED FACILITIES	1,466,695
15	U_BAYSIDE-GISLER FO (03199) PROPOSE	1,465,600
16	BSH-Plt 4 Interior Infrastructure R	1,461,795
17	Camp Edison-Registration Bldg Remod	1,460,788
18	Alpha-Water Valley: Alpha and Beta	1,445,896
19	2014 C&C - Tools - Interior CIT	1,436,897
20	Lugo: Install new SPS relays and co	1,435,174
21	DH LH RELO OH CALTRANS - I-5 @ VALL	1,434,452
22	Whirlwind Substation Interconnectio	1,426,809
23	Whirlwind(IF):Instl pos for Desert	1,419,449
24	Eagle Rock: Upgrade line protection	1,393,951
25	VA-CONSTRUCT NEW 8 MI 115KV LINE FO	1,392,909
26	Devers: Equip the 230 KV A-Bank pos	1,388,993
27	RULE 20B - UG INSTALL RULE 20B - UG	1,388,204
28	ColRvr(NU): 220kV Line/Bank Pos for	1,381,469
29	4703-0440--ET-NW-HIGHLAND* GOLDTOW	1,380,315
30	Somerset 66/4.16 (D) 1. Install new	1,379,868
31	PV2ER-Polar Crane U2	1,371,320
32	SA CAP ONRAMP/SERRANO LAY DOWN PROJ	1,361,515
33	U_Carpinteria-Ventura FO Cable 0614	1,359,096
34	Playa: Upgrade SAS	1,352,528
35	CO 43 OOZCO REBUILD 66KV RACK AT AL	1,349,693
36	Wave Sub:Replace No. 1 <(>&<)>2 Ban	1,336,887
37	SC: RC/JS NATURAL 66/12 NEW CUST SU	1,336,547
38	U_06137 Chatsworth-Natural FO Cable	1,331,533
39	WDT421 Cottonwood Sub: Equip 33 kV	1,325,563
40	Lugo Substation: Replace 500kV line	1,323,521
41	9219-2081--CPUC - IVYGLEN TO VALLEY	1,322,021
42	CMS Package 3 Master	1,307,669
43	TOTAL	3,203,958,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Villa Park: Install necessary phaso	1,306,438
2	46 DSP DSPCUT OVER 77 TRANSFORMERS	1,306,427
3	SAS Consolidation & Modernization	1,299,028
4	RELOCATE FACILITIES RELOCATE FACILI	1,297,392
5	ACQ: Falcon Ridge, Fontana/Rancho C	1,296,170
6	Serrano: Replace No. 2 AA bank	1,295,727
7	INFRASTRUCTURE REPLACEMENT (SPECIAL	1,292,846
8	TLRR 4201708 (74)Evaluate for possi	1,287,522
9	DSP DSPEXTEND WANDA 12KV O/O SUNNYS	1,274,687
10	NERC CIP V.5 - AMR - Master WO	1,269,029
11	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,262,521
12	NERC CIP v5 - SSM Project - BKRC2 -	1,255,793
13	Moorpark: Add 2 66kv CB's, add 5 66	1,251,245
14	DH CS CH CAP ON RAMP RECABLE PHASE	1,249,974
15	NEB Complete 07/18/2015	1,246,880
16	5061-5098--LUGO: INSTALL ONLINE DIS	1,241,044
17	Red Bluff (IF): Install One 80 feet	1,238,607
18	Browning Substation: Replace No. 1	1,232,742
19	DSP	1,226,537
20	RELO OH HAWTHORNE - AVIATION & MARI	1,222,693
21	La Fresa :Install 4 GE N60 rel. CRA	1,220,422
22	6572-8260-88229	1,216,069
23	Red Bluff Sub: Install the followi	1,211,245
24	32 INFRASTRUCTURE REPLACEMENT (COND	1,211,079
25	Imperial Substation: Replace No. 3	1,203,566
26	NCV5_CS-EL NIDO SUB	1,195,109
27	RULE 20B - UG INSTALL RULE 20B - UG	1,193,762
28	RELOCATE FACILITIES	1,192,972
29	BSH - Lundy Reline Return Ditch	1,191,772
30	Colorado River (IF): Install facili	1,191,356
31	DH JE PROJ 152 EXPO OH TO UG SEPULV	1,181,208
32	RELOCATE FACILITIES-BILLING - BILLI	1,177,666
33	Grid Mod: Analytics Platform- Serve	1,177,066
34	SC AM/YW CAP ON RAMP FAA	1,172,308
35	GM - Grid Analytics Plat - Master	1,170,541
36	SC PG-ELDORADO SUBSTATION CONTROL R	1,168,167
37	VA-Capital On Ramp-For South 40 (V	1,166,607
38	Antelope(IF): Install rack pos. & r	1,160,518
39	RULE 20B - UG INSTALL RULE 20B - UG	1,150,076
40	NCV5_CS-LUGO	1,147,910
41	SHEARIAE-11I-NtwkUp-Abengoa-WaterVa	1,145,849
42	Hanford-Replace No.3N <(>&<)> 3S Ba	1,141,991
43	TOTAL	3,203,958,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PLANT BETTERMENT/UPGRADING DISTRIBU	1,135,891
2	8049-5065--VICTOR SUB: UPGRADE PROT	1,130,027
3	DSP DSPMONTEBELLO ELIMINATION PROJE	1,128,405
4	5035-5035-- VESTAL: INSTALL BUSHING	1,126,847
5	Deferred" BSH-Waugh(RushMeadow)Dam	1,125,935
6	CAUDILJ-15I-Alhambra-DataRefresh	1,123,953
7	NCV5_CS-VISTA	1,121,472
8	46 DSP DSPCUT OVER 77 TRANSFORMERS	1,121,232
9	SC RC/KH 4605-1874--CHATSWORTH-MACN	1,120,378
10	ADDED FACILITIES	1,120,231
11	DAVILASL-15I-PIV-2 New Building	1,118,437
12	Safety Observations	1,117,739
13	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,116,950
14	Del Amo Substation: Replace AC Dist	1,115,038
15	NCV5_CS-VINCENT SUB	1,107,248
16	PV1PM - Dig Upgrd Generrex Unit 1	1,106,525
17	C&C ID - Firewall Appliances	1,106,071
18	DH LH CARMENITA-MURPHY-PIONEER-TELE	1,095,559
19	Greenhorn Sub: Replace Transformer	1,095,248
20	NCV5_CS-VALLEY SUB	1,093,507
21	eDMRM 2015 Project	1,091,618
22	ADDED FACILITIES ADDED FACILITIES	1,090,422
23	EE - MC3 Unit 5 Turbine Replacement	1,087,256
24	Operating Software & Middleware	1,086,864
25	Benefits - Union Negotiations	1,085,552
26	U_Midway - Delano FO Cable(07074)_R	1,081,342
27	ONI R2 HANA HW ADC	1,080,740
28	Vincent Substation: Replace 500kV l	1,079,631
29	PVCC - PRA Model - Fire	1,078,788
30	ADDED FACILITIES	1,078,086
31	RELOCATE FACILITIES	1,074,870
32	Betterment EMT retro fit Prv Lnd ET	1,072,743
33	5312-5022--LIBERTY: EQUIP 66KV LINE	1,069,590
34	Big Creek 2 Substation: Replace lin	1,068,276
35	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,063,682
36	RELOCATE FACILITIES RELOCATE FACILI	1,063,434
37	6735-7176-87105 PCH Hwy/Carbon Cyn,	1,061,513
38	Bowl Sub: Replace No. 1 &2 Banks 66	1,057,149
39	U_Mcgen-Ridgecrest DO FOC_CRF	1,047,621
40	DAVILASL-14I-Ventura:ContModer-Vent	1,045,917
41	EMT RETRO-FIT BETTERMENT M5/T1(69)	1,031,689
42	NV Energy Magnolia-NSO 230 kV Line	1,028,647
43	TOTAL	3,203,958,208

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	RULE 20B - UG INSTALL EUCALYTPUS/PE	1,025,774
2	PV3PM - Dig Upgrad Generex	1,024,449
3	2015 GRC Ph2	1,021,844
4	RI-4570-4903--CALECTRIC-HOMART 115K	1,018,629
5	ACQ - Santa Barbara Reliability	1,016,273
6	Tortilla Substation (IF): Construct	1,005,753
7	U_Inyokern-Mcgen FOC _CRF	1,003,227
8	San Antonio Substation: Replace (18	1,001,865
9	FIP-CHUG Civil Portion of undergrou	178,969,336
10		
11	Work Orders Under $1,000,000	895,620,437
12		
13		
14		
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43	TOTAL	3,203,958,208

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	11,399,887,618	11,399,887,618		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,251,307,289	1,251,307,289		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,254,437	1,254,437		
7	Other Clearing Accounts	8,758,627	8,758,627		
8	Other Accounts (Specify, details in footnote):	205,410,060	205,410,060		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,466,730,413	1,466,730,413		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	398,670,442	398,670,442		
13	Cost of Removal	609,088,127	609,088,127		
14	Salvage (Credit)	85,510,087	85,510,087		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	922,248,482	922,248,482		
16	Other Debit or Cr. Items (Describe, details in footnote):	-72,934,146	-72,934,146		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	11,871,435,403	11,871,435,403		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,363,120	3,363,120		
21	Nuclear Production	1,580,617,932	1,580,617,932		
22	Hydraulic Production-Conventional	438,301,907	438,301,907		
23	Hydraulic Production-Pumped Storage				
24	Other Production	458,853,354	458,853,354		
25	Transmission	2,142,777,663	2,142,777,663		
26	Distribution	6,236,257,512	6,236,257,512		
27	Regional Transmission and Market Operation				
28	General	1,011,263,915	1,011,263,915		
29	TOTAL (Enter Total of lines 20 thru 28)	11,871,435,403	11,871,435,403		

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

Amortization.

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

Other Items.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Energy Services Inc.			
2	Capital Stock	12/06/68	none	10
3	Additional Paid-in Capital	12/06/68	none	99,990
4	Undistributed Earnings	-	-	7,844,980
5	Subtotal			7,944,980
6				
7	Mono Power Company			
8	Capital Stock	03/02/70	none	100
9	Additional Paid-in Capital	03/02/70	none	2,749,150
10	Undistributed Earnings	-	-	-2,080,756
11	Subtotal			668,494
12				
13	Southern States Realty			
14	Capital Stock	01/22/73	none	100
15	Additional Paid-in Capital	01/22/73	none	
16	Undistributed Earnings	-	-	52,777
17	Subtotal			52,877
18				
19	SCE Capital Company			
20	Capital Stock	09/10/82	none	
21	Additional Paid-in Capital	09/10/82	none	
22	Undistributed Earnings	-	-	
23	Subtotal			
24		Rounding		
25				
26				
27				
28				
29	Subtotal			
30				
31				
32				
33				
34				
35	Subtotal			
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 2,849,350		TOTAL	8,666,351

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4		-	-	
5	Subtotal			
6				
7				
8				
9				
10				
11				
12				
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37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 2,849,350		TOTAL	8,666,351

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
149,902				4
149,902				5
				6
				7
		100		8
		2,749,150		9
-713		-2,081,469		10
-713		667,781		11
				12
				13
		100		14
				15
1,891		54,667		16
1,891		54,767		17
				18
				19
				20
				21
				22
				23
		1		24
				25
				26
				27
				28
		1		29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
151,080		722,549		42

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
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				41
151,080		722,549		42

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

* Energy Services Inc. dissolved as of September 14, 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)	6,768,745	4,378,586	
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)	249,856,519	237,511,350	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	14,399,085	16,647,665	
8	Transmission Plant (Estimated)	402,967	-286,684	
9	Distribution Plant (Estimated)	2,986,267	-1,878,674	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	584,152	-344,955	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	268,228,990	251,648,702	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	274,997,735	256,027,288	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	332,190.00	708,908	289,632.00	654,012
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	235,533.00	561,730		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Excess V2015 to FMV		98,849		
23	Transfer to Catalina				
24	Expired NOx	42,260.00	21,130		
25	True-up	298.00	149		
26					
27					
28	Total	42,558.00	120,128		
29	Balance-End of Year	54,099.00	27,050	289,632.00	654,012
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
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
289,632.00	622,076	273,551.00	591,737	2,798,390.00	4,538,097	3,983,395.00	7,114,830	1
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								10
								11
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								17
						235,533.00	561,730	18
								19
								20
								21
							98,849	22
								23
						42,260.00	21,130	24
						298.00	149	25
								26
								27
						42,558.00	120,128	28
289,632.00	622,076	273,551.00	591,737	2,798,390.00	4,538,097	3,705,304.00	6,432,972	29
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	NONE.					
2						
3						
4						
5						
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7						
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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
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	SONGS #2 - Amount to be amortized	15,702,337		407		1,015,366
22	over the authorized License Term					
23	January 1989 to July 2022					
24						
25	SONGS #3 - Amount to be amortized	15,296,205		407		990,811
26	over the authorized License Term					
27	January 1989 to July 2022					
28						
29	Palo Verde Nuclear Generating	7,772,588		407	-47,322	542,723
30	Station over the authorized					
31	License Term January 1989 to					
32	July 2022					
33						
34	Legacy Meters-Amount to be	321,813,920		407	-49,093,417	98,186,834
35	amortized over a 6 year period					
36	beginning January 2012 to					
37	December 2017					
38						
39	Mohave Generating Station Plant	60,543,424		407	-25,131,790	-1,288,330
40	over the authorized License Term					
41	January 2006 to June 2016					
42						
43	Chino Hills Underground	13,167,203		407	40,570	64,234
44						
45						
46						
47						
48						
49	TOTAL	434,295,677			-74,231,959	99,511,638

Schedule Page: 230 Line No.: 34 Column: a

SCE's request to use this account is pending approval from the commission.

Schedule Page: 230 Line No.: 39 Column: a

SCE's request to use this account is pending approval from the commission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Interconnection Studies	170,803	143	299,402	143
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Interconnection Studies	2,973,192	143	(3,533,591)	143
23					
24					
25					
26					
27					
28					
29					
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32					
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40					

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

Project Type	Order Description	Costs Incurred	Account Charged	Reimbursements	Account Credited
Transmission	800064614 Interconnection Study	648.70	143	887.64	143
Transmission	800250922 Interconnection Study	1,240.85	143	-	143
Transmission	800293812 Interconnection Study	101,831.99	143	-	143
Transmission	900522032 Interconnection Study	-	143	327,240.00	143
Transmission	900560735 Interconnection Study	32,772.38	143	74,454.74	143
Transmission	900816970 Interconnection Study	1,407.08	143	-	143
Transmission	901131640 Interconnection Study	10,248.59	143	-	143
Transmission	901192519 Interconnection Study	(18.05)	143	-	143
Transmission	901240728 Interconnection Study	219.59	143	(3,000.36)	143
Transmission	901254697 Interconnection Study	13.20	143	(180.31)	143
Transmission	901390841 Interconnection Study	1,066.75	143	-	143
Transmission	901484741 Interconnection Study	21,371.87	143	(100,000.00)	143
Total Transmission		**$ 170,802.95**		**$ 299,401.71**	

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

Column (b) may not include A and G expenses for the entire period.

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

Column (d) includes refunds that were paid to the Interconnection customer in 2015 resulting from payments received exceeding actual study costs and includes interest payments on refunds. Multiple orders for the same project may net to actual payments/disbursements to customers.

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

Project Type	Order Description	Costs Incurred	Account Charged	Reimbursements	Account Credited
Generation	800063892 Interconnection Study	(227.18)	143	-	143
Generation	800063932 Interconnection Study	1,186.50	143	19,829.09	143
Generation	800063947 Interconnection Study	790.77	143	(17,198.94)	143
Generation	800064040 Interconnection Study	(1,704.14)	143	(19,824.95)	143
Generation	800064064 Interconnection Study	897.68	143	63,106.18	143
Generation	800064074 Interconnection Study	(3.94)	143	(114.33)	143
Generation	800064106 Interconnection Study	(1,038.42)	143	24,357.99	143
Generation	800064109 Interconnection Study	(585.32)	143	15,446.58	143
Generation	800064132 Interconnection Study	37.96	143	(16,842.49)	143
Generation	800064136 Interconnection Study	956.43	143	37,450.81	143
Generation	800064255 Interconnection Study	3,581.21	143	65,143.37	143
Generation	800064269 Interconnection Study	2,605.81	143	(42,779.31)	143
Generation	800064320 Interconnection Study	-	143	24,000.00	143
Generation	800064388 Interconnection Study	-	143	(24,000.00)	143
Generation	800064467 Interconnection Study	2,348.73	143	(43,822.90)	143
Generation	800064497 Interconnection Study	2,726.61	143	(44,926.26)	143

Generation	800064588 Interconnection Study	477.04	143	1,892.13	143
Generation	800112779 Interconnection Study	3,812.16	143	13,640.90	143
Generation	800307351 Interconnection Study	4,337.79	143	(4,236.87)	143
Generation	800358038 Interconnection Study	(133.30)	143	-	143
Generation	800476775 Interconnection Study	-	143	5,528.27	143
Generation	800476778 Interconnection Study	5,409.98	143	11,269.86	143
Generation	800476782 Interconnection Study	464.31	143	10,570.58	143
Generation	800492450 Interconnection Study	(206.33)	143	-	143
Generation	900183819 Interconnection Study	1,111.89	143	(3,622.36)	143
Generation	900196938 Interconnection Study	477.14	143	33,432.26	143
Generation	900232332 Interconnection Study	47,244.73	143	269,685.27	143
Generation	900268276 Interconnection Study	(140,040.16)	143	29,417.93	143
Generation	900344938 Interconnection Study	1,092.55	143	-	143
Generation	900452414 Interconnection Study	3,097.35	143	(88,155.22)	143
Generation	900452465 Interconnection Study	109.24	143	(9,229.67)	143
Generation	900452738 Interconnection Study	1,237.21	143	(10,605.89)	143
Generation	900504769 Interconnection Study	12,010.10	143	148,035.14	143
Generation	900538864 Interconnection Study	3,832.25	143	(4,590.02)	143
Generation	900580158 Interconnection Study	2,699.08	143	(25,541.12)	143
Generation	900665750 Interconnection Study	4,923.52	143	2,362.29	143
Generation	900686844 Interconnection Study	252.08	143	(7,620.46)	143
Generation	900697213 Interconnection Study	5,899.89	143	27,875.33	143
Generation	900698682 Interconnection Study	6,077.24	143	39,328.81	143
Generation	900698688 Interconnection Study	5,722.90	143	45,358.66	143
Generation	900698689 Interconnection Study	5,705.69	143	45,395.23	143
Generation	900698698 Interconnection Study	5,735.30	143	70,489.66	143
Generation	900705435 Interconnection Study	7,470.99	143	81,390.94	143
Generation	900769596 Interconnection Study	863.11	143	-	143
Generation	900928251 Interconnection Study	3,134.80	143	(8,896.00)	143
Generation	900943705 Interconnection Study	82.95	143	-	143
Generation	900980746 Interconnection Study	90.51	143	-	143
Generation	900984553 Interconnection Study	12,397.23	143	(100,977.90)	143
Generation	900984556 Interconnection Study	13,082.80	143	(117,921.95)	143
Generation	900984557 Interconnection Study	13,222.95	143	(119,490.44)	143
Generation	900984558 Interconnection Study	13,174.00	143	(118,700.96)	143
Generation	900984604 Interconnection Study	13,394.43	143	(119,242.84)	143
Generation	900984605 Interconnection Study	13,100.59	143	(119,071.91)	143
Generation	901001497 Interconnection Study	11,286.68	143	(9,338.23)	143
Generation	901002000 Interconnection Study	11,082.15	143	(20,401.17)	143
Generation	901002466 Interconnection Study	11,462.43	143	(10,592.26)	143
Generation	901002467 Interconnection Study	11,315.17	143	(8,649.47)	143
Generation	901002469 Interconnection Study	11,234.75	143	(8,917.55)	143
Generation	901002703 Interconnection Study	11,385.61	143	(21,000.37)	143
Generation	901004320 Interconnection Study	11,354.98	143	90,498.95	143
Generation	901005580 Interconnection Study	64,580.95	143	-	143

FOOTNOTE DATA

Generation	901014597 Interconnection Study	181.50	143	-	143
Generation	901061801 Interconnection Study	699.42	143	-	143
Generation	901069751 Interconnection Study	4,449.86	143	-	143
Generation	901070519 Interconnection Study	15,980.28	143	-	143
Generation	901070520 Interconnection Study	14,170.06	143	-	143
Generation	901070521 Interconnection Study	12,043.62	143	97,170.67	143
Generation	901070522 Interconnection Study	15,054.78	143	98,901.30	143
Generation	901070523 Interconnection Study	2,572.54	143	95,365.35	143
Generation	901070524 Interconnection Study	15,577.99	143	-	143
Generation	901091908 Interconnection Study	10,520.25	143	(15,318.79)	143
Generation	901107867 Interconnection Study	90.65	143	-	143
Generation	901111634 Interconnection Study	3,268.76	143	-	143
Generation	901127208 Interconnection Study	900.92	143	-	143
Generation	901127210 Interconnection Study	218.30	143	-	143
Generation	901130674 Interconnection Study	7,642.41	143	71,654.18	143
Generation	901214021 Interconnection Study	2,330.19	143	-	143
Generation	901215956 Interconnection Study	(54,265.23)	143	(62,233.92)	143
Generation	901253252 Interconnection Study	65.81	143	-	143
Generation	901260641 Interconnection Study	328.64	143	(4,261.39)	143
Generation	901264229 Interconnection Study	2,226.41	143	-	143
Generation	901267947 Interconnection Study	(14,166.10)	143	(85,652.87)	143
Generation	901267948 Interconnection Study	(30,126.38)	143	-	143
Generation	901267949 Interconnection Study	(30,059.07)	143	(71,123.54)	143
Generation	901267951 Interconnection Study	23,467.50	143	(80,566.17)	143
Generation	901267952 Interconnection Study	13,154.85	143	(69,291.91)	143
Generation	901267953 Interconnection Study	13,563.22	143	(71,482.14)	143
Generation	901267954 Interconnection Study	13,158.22	143	(69,819.61)	143
Generation	901267955 Interconnection Study	(37,104.98)	143	(70,694.64)	143
Generation	901267956 Interconnection Study	13,424.53	143	(70,659.50)	143
Generation	901267958 Interconnection Study	13,835.55	143	(71,892.17)	143
Generation	901268099 Interconnection Study	13,913.85	143	(71,952.37)	143
Generation	901268873 Interconnection Study	187.24	143	-	143
Generation	901276372 Interconnection Study	11,559.33	143	18,845.71	143
Generation	901276374 Interconnection Study	10,917.18	143	35,020.93	143
Generation	901276881 Interconnection Study	14,897.72	143	-	143
Generation	901276882 Interconnection Study	14,040.47	143	-	143
Generation	901276919 Interconnection Study	14,445.56	143	-	143
Generation	901276920 Interconnection Study	15,054.86	143	68,826.57	143
Generation	901276921 Interconnection Study	1,886.90	143	68,178.50	143
Generation	901276922 Interconnection Study	15,661.63	143	27,641.22	143
Generation	901276923 Interconnection Study	14,420.07	143	28,924.98	143

Generation	901276925 Interconnection Study	14,065.17	143	-	143
Generation	901276926 Interconnection Study	15,848.99	143	-	143
Generation	901279713 Interconnection Study	11,649.23	143	32,910.23	143
Generation	901279714 Interconnection Study	11,474.19	143	33,949.32	143
Generation	901279715 Interconnection Study	11,447.23	143	-	143
Generation	901279716 Interconnection Study	15,108.42	143	-	143
Generation	901279717 Interconnection Study	11,906.72	143	34,065.75	143
Generation	901279961 Interconnection Study	14,815.70	143	-	143
Generation	901280667 Interconnection Study	187.24	143	-	143
Generation	901280669 Interconnection Study	248.33	143	-	143
Generation	901284618 Interconnection Study	5,199.37	143	41,887.83	143
Generation	901284706 Interconnection Study	9,273.70	143	-	143
Generation	901284707 Interconnection Study	2,376.15	143	154,052.13	143
Generation	901284708 Interconnection Study	19,156.49	143	200,237.32	143
Generation	901284712 Interconnection Study	17,001.53	143	-	143
Generation	901284713 Interconnection Study	14,725.28	143	-	143
Generation	901284714 Interconnection Study	1,355.47	143	58,577.60	143
Generation	901284715 Interconnection Study	13,552.90	143	-	143
Generation	901284955 Interconnection Study	186.98	143	-	143
Generation	901284957 Interconnection Study	(7,310.37)	143	-	143
Generation	901285159 Interconnection Study	187.31	143	-	143
Generation	901285165 Interconnection Study	248.68	143	-	143
Generation	901285168 Interconnection Study	12,440.56	143	(60,030.31)	143
Generation	901285369 Interconnection Study	10,029.04	143	-	143
Generation	901285758 Interconnection Study	1,241.74	143	-	143
Generation	901285837 Interconnection Study	824.05	143	(5,878.90)	143
Generation	901288829 Interconnection Study	637.68	143	(8,315.22)	143
Generation	901336736 Interconnection Study	-	143	800.00	143
Generation	901337640 Interconnection Study	281.66	143	(28,904.73)	143
Generation	901337641 Interconnection Study	5,416.57	143	(28,750.72)	143
Generation	901337642 Interconnection Study	6,362.34	143	(29,696.49)	143
Generation	901337643 Interconnection Study	5,606.99	143	(28,941.14)	143
Generation	901337644 Interconnection Study	11,043.45	143	(30,732.48)	143
Generation	901337645 Interconnection Study	4,693.57	143	(26,339.01)	143
Generation	901337646 Interconnection Study	3,304.71	143	(26,638.86)	143
Generation	901337647 Interconnection Study	8,496.84	143	(32,045.74)	143
Generation	901337648 Interconnection Study	5,897.13	143	(29,231.28)	143
Generation	901337649 Interconnection Study	3,816.00	143	(27,311.22)	143
Generation	901337651 Interconnection Study	5,810.77	143	(29,144.92)	143
Generation	901337652 Interconnection Study	4,477.21	143	(27,811.36)	143
Generation	901337653 Interconnection Study	3,980.71	143	(27,314.86)	143
Generation	901337654 Interconnection Study	5,416.99	143		143

FOOTNOTE DATA

				(28,751.14)	
Generation	901337655 Interconnection Study	10,330.97	143	(29,284.67)	143
Generation	901337656 Interconnection Study	6,160.25	143	(29,709.15)	143
Generation	901337657 Interconnection Study	6,099.81	143	(29,433.96)	143
Generation	901337658 Interconnection Study	5,180.84	143	(28,514.99)	143
Generation	901337659 Interconnection Study	5,870.79	143	(29,204.94)	143
Generation	901337660 Interconnection Study	5,256.08	143	(28,591.97)	143
Generation	901368278 Interconnection Study	202.20	143	-	143
Generation	901368400 Interconnection Study	278.18	143	-	143
Generation	901368401 Interconnection Study	596.38	143	-	143
Generation	901369103 Interconnection Study	106.98	143	-	143
Generation	901369761 Interconnection Study	(134.68)	143	-	143
Generation	901369764 Interconnection Study	29.46	143	52,357.42	143
Generation	901374559 Interconnection Study	(52.71)	143	-	143
Generation	901377397 Interconnection Study	-	143	1,500.00	143
Generation	901378862 Interconnection Study	(33.96)	143	-	143
Generation	901381678 Interconnection Study	1,117.62	143	-	143
Generation	901386568 Interconnection Study	(37.55)	143	-	143
Generation	901389795 Interconnection Study	9,220.51	143	-	143
Generation	901390331 Interconnection Study	15,225.13	143	-	143
Generation	901391672 Interconnection Study	396.27	143	-	143
Generation	901391673 Interconnection Study	470.03	143	-	143
Generation	901391899 Interconnection Study	382.74	143	-	143
Generation	901391900 Interconnection Study	647.87	143	-	143
Generation	901394429 Interconnection Study	372.03	143	-	143
Generation	901394436 Interconnection Study	372.03	143	-	143
Generation	901395069 Interconnection Study	1,534.45	143	-	143
Generation	901397051 Interconnection Study	731.77	143	-	143
Generation	901397052 Interconnection Study	306.28	143	-	143
Generation	901397054 Interconnection Study	243.11	143	-	143
Generation	901397056 Interconnection Study	306.26	143	-	143
Generation	901397057 Interconnection Study	558.85	143	-	143
Generation	901397058 Interconnection Study	306.26	143	-	143
Generation	901397282 Interconnection Study	1,863.84	143	-	143
Generation	901397284 Interconnection Study	415.12	143	-	143
Generation	901397285 Interconnection Study	1,966.12	143	-	143
Generation	901397287 Interconnection Study	881.63	143	-	143
Generation	901397288 Interconnection Study	946.98	143	-	143
Generation	901397289 Interconnection Study	783.53	143	-	143
Generation	901397291 Interconnection Study	526.91	143	-	143
Generation	901397292 Interconnection Study	1,275.75	143	-	143
Generation	901406004 Interconnection Study		143	-	143

FOOTNOTE DATA

		433.91			
Generation	901412731 Interconnection Study	(27.53)	143	-	143
Generation	901412732 Interconnection Study	(22.86)	143	0.00	143
Generation	901438687 Interconnection Study	1,493.72	143	-	143
Generation	901439990 Interconnection Study	348.26	143	-	143
Generation	901454045 Interconnection Study	626.52	143	-	143
Generation	901454046 Interconnection Study	626.52	143	-	143
Generation	901454047 Interconnection Study	626.52	143	-	143
Generation	901465757 Interconnection Study	4,181.50	143	(4,181.50)	143
Generation	901481140 Interconnection Study	177,739.90	143	-	143
Generation	901483673 Interconnection Study	459.40	143	(1,500.00)	143
Generation	901483674 Interconnection Study	1,102.83	143	(1,500.00)	143
Generation	901487486 Interconnection Study	1,342.70	143	(2,500.00)	143
Generation	901487736 Interconnection Study	2,710.15	143	(2,710.15)	143
Generation	901501009 Interconnection Study	78.11	143	(800.00)	143
Generation	901515929 Interconnection Study	1,047.17	143	(0.30)	143
Generation	901531407 Interconnection Study	3,946.09	143	(90,000.00)	143
Generation	901532618 Interconnection Study	34,711.35	143	-	143
Generation	901532780 Interconnection Study	34,679.99	143	-	143
Generation	901532781 Interconnection Study	34,669.17	143	-	143
Generation	901532782 Interconnection Study	45,417.51	143	-	143
Generation	901532783 Interconnection Study	34,044.47	143	-	143
Generation	901532784 Interconnection Study	35,264.65	143	-	143
Generation	901532786 Interconnection Study	33,597.79	143	-	143
Generation	901532787 Interconnection Study	32,976.10	143	-	143
Generation	901532788 Interconnection Study	46,742.38	143	-	143
Generation	901532789 Interconnection Study	47,333.50	143	-	143
Generation	901532790 Interconnection Study	41,831.51	143	-	143
Generation	901532791 Interconnection Study	35,154.13	143	-	143
Generation	901532792 Interconnection Study	46,613.18	143	-	143
Generation	901532793 Interconnection Study	19,434.75	143	-	143
Generation	901532795 Interconnection Study	37,607.29	143	-	143
Generation	901532797 Interconnection Study	34,352.50	143	-	143
Generation	901532798 Interconnection Study	32,846.78	143	-	143
Generation	901532800 Interconnection Study	44,938.81	143	-	143
Generation	901532801 Interconnection Study	45,658.60	143	-	143
Generation	901532802 Interconnection Study	45,350.23	143	-	143
Generation	901532848 Interconnection Study	22,402.11	143	(70,000.00)	143
Generation	901532855 Interconnection Study	22,366.82	143	(70,000.00)	143
Generation	901532856 Interconnection Study	21,304.49	143	(70,000.00)	143
Generation	901534761 Interconnection Study	2,205.15	143	(51,000.00)	143
Generation	901534951 Interconnection Study	33,641.64	143	(70,000.00)	143

FOOTNOTE DATA

Generation	901534952 Interconnection Study	21,927.27	143	(120,000.00)	143
Generation	901535370 Interconnection Study	23,736.14	143	(100,000.00)	143
Generation	901535371 Interconnection Study	1,265.99	143	(494.84)	143
Generation	901535522 Interconnection Study	436.87	143	362.58	143
Generation	901536898 Interconnection Study	29,949.18	143	(70,000.00)	143
Generation	901536972 Interconnection Study	3,596.87	143	(70,000.00)	143
Generation	901536974 Interconnection Study	21,480.16	143	(92,000.00)	143
Generation	901536975 Interconnection Study	3,661.90	143	(75,000.00)	143
Generation	901536976 Interconnection Study	21,632.05	143	(80,000.00)	143
Generation	901537760 Interconnection Study	1,843.78	143	(100,000.00)	143
Generation	901538460 Interconnection Study	6,975.94	143	(58,000.00)	143
Generation	901545904 Interconnection Study	2,515.74	143	(1,422.71)	143
Generation	901546416 Interconnection Study	24,973.87	143	(65,000.00)	143
Generation	901547504 Interconnection Study	24,024.32	143	(90,000.00)	143
Generation	901551199 Interconnection Study	1,291.07	143	(742.41)	143
Generation	901551201 Interconnection Study	1,291.07	143	(742.41)	143
Generation	901551293 Interconnection Study	1,009.28	143	(418.12)	143
Generation	901551294 Interconnection Study	20,529.19	143	(53,000.00)	143
Generation	901551295 Interconnection Study	22,647.26	143	(53,000.00)	143
Generation	901551296 Interconnection Study	22,692.82	143	(53,000.00)	143
Generation	901551297 Interconnection Study	31,486.57	143	(66,000.00)	143
Generation	901551708 Interconnection Study	2,209.88	143	(2,100.00)	143
Generation	901551710 Interconnection Study	21,800.36	143	(60,000.00)	143
Generation	901551711 Interconnection Study	23,771.84	143	(70,000.00)	143
Generation	901551712 Interconnection Study	1,820.75	143	(10,000.00)	143
Generation	901551713 Interconnection Study	21,926.35	143	(70,000.00)	143
Generation	901551714 Interconnection Study	20,841.01	143	(70,000.00)	143
Generation	901551715 Interconnection Study	23,765.87	143	(100,000.00)	143
Generation	901551716 Interconnection Study	23,153.34	143	(65,000.00)	143
Generation	901552104 Interconnection Study	1,599.96	143	(65,000.00)	143
Generation	901552105 Interconnection Study	737.27	143	(100,000.00)	143
Generation	901552106 Interconnection Study	1,590.75	143	(65,000.00)	143
Generation	901552107 Interconnection Study	1,272.62	143	(150,000.00)	143
Generation	901552108 Interconnection Study	1,079.06	143	(65,000.00)	143
Generation	901552109 Interconnection Study	1,085.44	143	(75,000.00)	143
Generation	901552366 Interconnection Study	24,171.35	143	-	143
Generation	901552369 Interconnection Study	22,094.46	143	(3,580.02)	143
Generation	901552942 Interconnection Study	4,911.10	143	(90,000.00)	143
Generation	901552954 Interconnection Study	22,236.37	143	(3,221.64)	143
Generation	901552955 Interconnection Study	22,680.26	143	(4,591.17)	143
Generation	901552958 Interconnection Study	22,703.38	143	(3,908.01)	143
Generation	901553024 Interconnection Study	22,991.24	143	(4,811.50)	143
Generation	901553025 Interconnection Study	21,761.89	143	(3,412.33)	143

Generation	901553026 Interconnection Study	5,378.80	143	(5,360.67)	143
Generation	901553027 Interconnection Study	22,480.94	143	(3,203.57)	143
Generation	901553028 Interconnection Study	1,209.76	143	(1,209.76)	143
Generation	901553029 Interconnection Study	1,458.03	143	(1,458.03)	143
Generation	901553030 Interconnection Study	22,079.04	143	(3,339.06)	143
Generation	901553031 Interconnection Study	21,356.94	143	(2,552.63)	143
Generation	901553032 Interconnection Study	22,151.42	143	(3,280.70)	143
Generation	901556613 Interconnection Study	22,718.47	143	(4,316.48)	143
Generation	901556614 Interconnection Study	23,020.63	143	(4,524.19)	143
Generation	901556615 Interconnection Study	22,687.54	143	(3,596.19)	143
Generation	901556616 Interconnection Study	24,227.05	143	(1,894.69)	143
Generation	901556617 Interconnection Study	21,601.40	143	(2,573.46)	143
Generation	901556618 Interconnection Study	3,720.15	143	(3,720.15)	143
Generation	901556999 Interconnection Study	636.15	143	(636.15)	143
Generation	901557000 Interconnection Study	1,538.17	143	(1,538.17)	143
Generation	901557001 Interconnection Study	24,666.90	143	(5,840.22)	143
Generation	901557002 Interconnection Study	22,197.87	143	(3,235.60)	143
Generation	901557003 Interconnection Study	22,374.83	143	(3,778.16)	143
Generation	901557004 Interconnection Study	7,634.19	143	(7,648.22)	143
Generation	901557005 Interconnection Study	21,219.54	143	(2,900.91)	143
Generation	901557270 Interconnection Study	2,853.19	143	(2,030.39)	143
Generation	901557271 Interconnection Study	22,823.40	143	(53,000.00)	143
Generation	901557272 Interconnection Study	23,816.96	143	(53,000.00)	143
Generation	901557273 Interconnection Study	22,506.30	143	(53,000.00)	143
Generation	901557277 Interconnection Study	3,967.00	143	(2,227.24)	143
Generation	901557278 Interconnection Study	20,683.70	143	(70,000.00)	143
Generation	901557300 Interconnection Study	21,886.04	143	(3,526.80)	143
Generation	901557301 Interconnection Study	21,318.85	143	(2,917.51)	143
Generation	901557492 Interconnection Study	21,540.01	143	(2,873.64)	143
Generation	901557493 Interconnection Study	21,004.06	143	(2,447.79)	143
Generation	901557923 Interconnection Study	21,246.44	143	(2,420.83)	143
Generation	901586603 Interconnection Study	2,254.78	143	(1,500.00)	143
Generation	901587104 Interconnection Study	952.98	143	-	143
Generation	901597364 Interconnection Study	28.59	143	(300.00)	143
Generation	901606564 Interconnection Study	369.72	143	(1,500.00)	143
Generation	901606565 Interconnection Study	2,339.78	143	(1,500.00)	143
Generation	901606566 Interconnection Study	494.70	143	(1,500.00)	143
Generation	901609748 Interconnection Study	434.35	143	(1,500.00)	143
Generation	901609750 Interconnection Study	426.95	143	(1,500.00)	143
Generation	901609752 Interconnection Study	520.06	143	(1,500.00)	143
Generation	901609755 Interconnection Study	426.95	143	(1,500.00)	143
Generation	901609781 Interconnection Study	459.24	143	(1,500.00)	143
Generation	901609784 Interconnection Study	903.48	143	(1,500.00)	143
Generation	901609785 Interconnection Study		143		143

		441.12		(1,500.00)	
Generation	901618377 Interconnection Study	646.81	143	(1,500.00)	143
Generation	901618378 Interconnection Study	462.27	143	(1,500.00)	143
Generation	901618679 Interconnection Study	855.40	143	(1,500.00)	143
Generation	901618680 Interconnection Study	260.83	143	(1,500.00)	143
Generation	901618681 Interconnection Study	2,218.93	143	(1,500.00)	143
Generation	901618682 Interconnection Study	840.61	143	(1,500.00)	143
Generation	901618683 Interconnection Study	1,261.66	143	(1,500.00)	143
Generation	901618684 Interconnection Study	1,132.80	143	(1,500.00)	143
Generation	901618685 Interconnection Study	879.54	143	(1,500.00)	143
Generation	901618686 Interconnection Study	263.41	143	(1,500.00)	143
Generation	901619818 Interconnection Study	663.65	143	(1,500.00)	143
Generation	901619899 Interconnection Study	796.92	143	(1,500.00)	143
Generation	901619901 Interconnection Study	464.34	143	(1,500.00)	143
Generation	901619905 Interconnection Study	425.84	143	(1,500.00)	143
Generation	901619907 Interconnection Study	687.42	143	(1,500.00)	143
Generation	901619908 Interconnection Study	1,419.93	143	(1,500.00)	143
Generation	901619909 Interconnection Study	1,206.10	143	(1,500.00)	143
Generation	901619910 Interconnection Study	819.84	143	(1,500.00)	143
Generation	901619911 Interconnection Study	484.24	143	(1,500.00)	143
Generation	901619912 Interconnection Study	325.11	143	(1,500.00)	143
Generation	901619913 Interconnection Study	461.69	143	(1,500.00)	143
Generation	901624519 Interconnection Study	465.39	143	(1,500.00)	143
Generation	901626585 Interconnection Study	445.34	143	(1,500.00)	143
Generation	901626586 Interconnection Study	425.84	143	(1,500.00)	143
Generation	901626587 Interconnection Study	719.99	143	(1,500.00)	143
Generation	901626588 Interconnection Study	899.87	143	(1,500.00)	143
Generation	901626589 Interconnection Study	354.51	143	(1,500.00)	143
Generation	901626590 Interconnection Study	450.84	143	(1,500.00)	143
Generation	901628565 Interconnection Study	1,438.63	143	(1,500.00)	143
Generation	901632978 Interconnection Study	1,168.09	143	-	143
Generation	901633308 Interconnection Study	220.84	143	-	143
Generation	901647076 Interconnection Study	187.59	143	(2,500.00)	143
Generation	901647077 Interconnection Study	187.59	143	(2,500.00)	143
Generation	901647078 Interconnection Study	407.03	143	(2,500.00)	143
Generation	901647159 Interconnection Study	407.03	143	(2,500.00)	143
Generation	901649251 Interconnection Study	951.07	143	(2,500.00)	143
Generation	901649252 Interconnection Study	614.40	143	(2,500.00)	143
Generation	901649254 Interconnection Study	514.24	143	(2,500.00)	143
Generation	901650188 Interconnection Study	1,155.92	143	(2,500.00)	143
Generation	901650189 Interconnection Study	850.35	143	(2,500.00)	143

FOOTNOTE DATA

Generation	901650190 Interconnection Study	1,109.45	143	(2,500.00)	143
Generation	901650191 Interconnection Study	692.39	143	(2,500.00)	143
Generation	901650664 Interconnection Study	405.10	143	(2,500.00)	143
Generation	901650665 Interconnection Study	57.56	143	(2,500.00)	143
Generation	901650666 Interconnection Study	641.68	143	(2,500.00)	143
Generation	901650667 Interconnection Study	193.86	143	(2,500.00)	143
Generation	901650668 Interconnection Study	193.86	143	(2,500.00)	143
Generation	901650670 Interconnection Study	273.04	143	(2,500.00)	143
Generation	901650671 Interconnection Study	273.04	143	(2,500.00)	143
Generation	901657349 Interconnection Study	1,196.22	143	(70,000.00)	143
Generation	901663890 Interconnection Study	379.32	143	(2,500.00)	143
Generation	901665080 Interconnection Study	70.73	143	(1,500.00)	143
Generation	901671284 Interconnection Study	162.00	143	(1,500.00)	143
Generation	901677974 Interconnection Study	-	143	(52,000.00)	143
Generation	901722145 Interconnection Study	-	143	(55,000.00)	143
Generation	901729523 Interconnection Study	-	143	(53,000.00)	143
	Total Generation	**$ 2,973,191.91**		**$ (3,533,591.42)**	

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

Column (b) may not include A and G expenses for the entire period.

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

Column (d) includes refunds that were paid to the Interconnection customer in 2015 resulting from payments received exceeding actual study costs and includes interest payments on refunds. Multiple orders for the same project may net to actual payments/disbursements to customers.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Income Tax-Related Deferred Charges	3,810,727,679	7,512,610,427	various	7,482,824,355	3,840,513,751
2	FASB 109 gross-up of taxes.					
3						
4	Unamortized Cost - Palo Verde Commercial	309,466		406	24,819	284,647
5	Operating Date Adjustment					
6	To recover costs incurred between FERC and					
7	CPUC commercial operating date.					
8	(Amortization Period: 03/1988-07/2046)					
9						
10	Palo Verde Units 2 & 3	1,244,374		406	99,799	1,144,575
11	To recover deferred common facilities charges.					
12	(Amortization Period: 09/1986 - 07/2046)					
13						
14	Coolwater Lugo		37,069,049			37,069,049
15	To reflect Coolwater Lugo project as regulatory					
16	assets					
17						
18	Catastrophic Event Memorandum Account	17,926,556	9,428,110	Various	16,548,091	10,806,575
19	To record costs incurred by SCE associated					
20	with a catastrophic event for restoring					
21	utility service to customers; repairing, replacing,					
22	or restoring damaged utility facilities; and					
23	complying with governmental agency orders.					
24						
25	Environmental Clean-up Costs	70,972,834	19,000,943	Various	8,082,739	81,891,038
26	To recover ratepayer's portion of environmental					
27	costs.					
28						
29	Hazardous Waste Balancing Account	1,328,632	1,972,517	254	1,849,967	1,451,182
30	To recover collaborative hazardous waste costs.					
31						
32	Post Employment Benefit Accrual	63,690,759				63,690,759
33	To reflect a regulatory asset for future recovery					
34	of post employment benefits associated with					
35	SFAS 112.					
36						
37	Environmental Remediation	35,887,513	20,969,577	Varios	9,977,190	46,879,900
38	To recover 90% of estimated future environmental					
39	remediation/cleanup costs.					
40						
41						
42						
43						
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	CARE Balancing Account		584,974	Various	584,974	
2	To reflect in rates, through application of the					
3	Public Purpose Program Charge the costs assoc-					
4	iated with the CARE Program as authorized in					
5	various CPUC Decisions.					
6						
7	Unamortized Nuclear Plant	83,619,929		Various	902,071	82,717,858
8	To reflect SONGS and Palo Verde Nuclear Plants as					
9	regulatory asset.					
10	(Amortization Period: 03/1988-07/2046)					
11						
12	Nuclear Asset Retirement Obligation (ARO)	8,393,406	5,783,224	406	6,564,946	7,611,684
13	To establish a regulatory asset for decommission-					
14	ing costs collected in rates for Nuclear and coal					
15	ARO property. (Amort. Period: 12/2003-12/2025)					
16						
17	Other Ratemaking	(4,211,008)	4,347,670	242	136,662	
18	Reclassification of other ratemaking amounts to a					
19	contra-asset account.					
20						
21	Bilateral Energy & Gas Financial Instruments	987,203,587	182,555,499			1,169,759,086
22	To record the mark-to-market adjustments related to					
23	the financial instruments used to hedge power					
24	purchases and natural gas costs for tolling.					
25						
26	Pension Costs Balancing Account		35,292,303	Various	35,198,414	93,889
27	To record the difference between pension costs					
28	authorized by the Commission, and recorded					
29	pension expenses.					
30						
31	Mohave Balancing Account	21,953,484	21,633,167	Various	43,586,651	
32	To track the difference between: (1) recorded					
33	capital-related expenses, operating expenses and					
34	worker protection expenses associated with the					
35	Mohave Generating Station; and (2) the authorized					
36	Mohave revenue requirement as adopted in					
37	D.09-03-025					
38						
39	Regulatory Asset Pension - SFAS 158	1,218,463,001	57,951,500	228	427,224,500	849,190,001
40	To reflect regulatory asset resulting from the					
41	adoption of SFAS 158 Employers' Accounting					
42	for Defined Benefit Pension & Other Postretirementl					
43	Plans.					
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Leases for Power Contracts	21,748,781	182,806	Various	5,549,053	16,382,534
3	To record regulatory asset associated with power					
4	contracts that are subject to lease accounting					
5	rules under the guidance of EITF No. 01-8 and					
6	SFAS 13.(Amortization Period: 12/2006- 4/2026)					
7						
8	Reclaim Training Credit (RTC)	1,163,914	251,954	407	1,317,019	98,849
9	To record a regulatory asset associated with the					
10	fair market adjustment for reclaim training					
11	credit (RTC).					
12						
13	Results Sharing Memorandum Account (RSMA)		106,223,046	407	106,223,046	
14	To track the difference between authorized and					
15	recorded Results Sharing expenses paid out.					
16						
17	Market Redesign and Technology Upgrade Memorandum	28,548,498	6,366,563	407	12,038,549	22,876,512
18	Account (MRTUMA)					
19	To record SCE's incremental costs associated with					
20	the CAISO's MRTU initiative.					
21						
22	Misc. Balancing Account Activity	58,260,437	22,120,327	Various	70,247,064	10,133,700
23	To capture various accrued purchased power					
24	agreements and other miscellaneous regulatory					
25	assets.					
26						
27	Fire Hazard Prevention Memorandum Account	105,788	160,787	407	338	266,237
28	To record the costs incurred related to fire hazard					
29	prevention in compliance with Commission Decision					
30	D.09-08-029.					
31						
32	Renewable Portfolio Standard Costs Memorandum	1,019,899	1,488			1,021,387
33	Account					
34	To record the (1) costs of studies of inter-					
35	connection facilities and network transmission up-					
36	grades necessary to interconnect RPS generation					
37	resources contracted in the 2003 and 2005 RPS					
38	solicitations and additional resources to be					
39	contracted in the future in accordance with					
40	ordering Paragraph No.1 of Resolution E-3969; (2)					
41	costs of studies associated with the Tehachapi					
42	Wind Resource Area, in accordance with Ordering					
43	Paragraph No. 2 of Resolution E-3969; and (3)					
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

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	payments allocated to SCE for contractor(s) hired					
2	by Executive Director of the Commission to provide					
3	technical and other support to Commission Staff in					
4	the advancement of RPS goals, pursuant to					
5	Ordering Paragraph 8 of D.06-10-050.					
6						
7	FAS 87 Pen Reg Asset	170,540,000	8,749,000	228	3,061,000	176,228,000
8	To record the cumulative difference between pension					
9	expense calculated for ratemaking purposes and the					
10	amount calculated for accounting purposes since					
11	implementation of SFAS 87.					
12						
13	Smart Grid American Recovery and Reinvestment Act	17,953,428	2,819,411	407	1,527,024	19,245,815
14	Memorandum Account					
15	To record SCE's incremental O&M expenses, incre-					
16	mental capital-related revenue requirements, and					
17	DOE funding consistent with Order Paragraph 2 of					
18	decision D.09-09-029.					
19						
20	Gas Cost Adjustment Billing Balancing Account	29,512	30,767	Various	60,279	
21	Balance composed of Gas Cost Adjustment Clause					
22	which recovers/refunds gas costs on Catalina					
23	Island.					
24						
25	SmartConnect Opt-Out Memo Account	5,418,244	537,466	Various	5,955,710	
26	To record the incremental expenditures required					
27	to implement SCE's Edison SmartConnect Opt-Out					
28	Program and the associated revenues from					
29	interim opt-out fees.					
30						
31	Transmission Access Charge Balancing Account	51,673,052	32,327,769	Various	75,748,280	8,252,541
32	To track the flow through to end-use customers					
33	the net cost-shift billed to SCE by the ISO under					
34	the Transmission Access Charge (TAC) as per					
35	Section 5.6 of the TO Tariff.					
36						
37	Energy Resource Recovery Account	1,028,465,692	276,196,096	Various	1,304,661,788	
38	To record SCE's ERRA Revenue, Utility Retained					
39	Generation fuel costs and purchased power related					
40	expenses.					
41						
42						
43						
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Incurred But Not Reported Medical Claims	5,206,709	6,469,779	407	1,910,202	9,766,286
2	To record a regulatory asset for					
3	estimated costs of medical services rendered for					
4	which claims have not been filed or invoiced					
5	(Incurred But Not Reported).					
6						
7	San Onofre Regulatory Asset	1,285,951,099	173,350,722	Various	408,481,772	1,050,820,049
8	To record San Onofre property, plant and equipment,					
9	and other as a regulatory asset.					
10						
11	New System Gen Balancing Account	34,741,767	44,583,522	Various	79,325,289	
12	The purpose of the New System Generation Balancing					
13	Account (NSGBA) is to record the benefits and costs					
14	of Power Purchase Agreements (PPAs) and SCE					
15	owned peaker generation unit associated with new					
16	generation resources.					
17						
18	Public Purpose Programs Adjustment Mechanism	131,634,475	431,352,195	Various	248,735,523	314,251,147
19	To record Public Goods Charge Revenue, PGC					
20	expenses authorized in P.U. Code Section 399.8, and					
21	other CPUC Public Purpose Program revenues and					
22	expenses.					
23						
24	Agricultural Account Aggregation Study Memorandum	19,403	32,450	407	932	50,921
25	Account					
26	The purpose of the Agricultural Account Aggregation					
27	Study Memorandum Account (AAASMA) is to record the					
28	costs, not to exceed $100,000, associated with a					
29	study that will examine the costs and benefits of					
30	agricultural customer account aggregation.					
31	Pursuant to Decision D.13-03-031, the costs of					
32	the study shall be recovered from Agricultural and					
33	Pumping customers through the distribution sub-					
34	account of the Base Revenue Requirement Balancing					
35	Account (BRRBA).					
36						
37	SONGS Technical Assistance Memorandum Account	3,202	5			3,207
38	To record Commission-approved invoices for					
39	consultant costs incurred by the Commission and					
40	paid by SCE in Connection with SONGS investigation.					
41						
42						
43						
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Base Revenue Requirement Balancing Account		3,134,763,105	Various	3,134,763,105	
2	To record the difference between SCE's authorized					
3	distribution and generation base revenue require-					
4	ment and recorded revenue from authorized distrib-					
5	ution and generation rates; and record other auth-					
6	orized and recorded costs authorized by the					
7	Commission.					
8						
9	FERC Formula Rate	2,115,577	134,983,689	Various	46,985,344	90,113,922
10	To record the difference between billed and unbill-					
11	ed revenue and the recorded transmission revenue					
12	requirement to cover the costs of owning and oper-					
13	ating transmission facilities under ISO Control.					
14						
15	Transmission Revenue Balancing Account	13,471,426	52,826,826	Various	66,298,252	
16	The purpose of TRBA is included in tariffs of all					
17	transmission owners that participate in the CAISO.					
18	The TRBA accounts for revenues that the transmiss-					
19	ion owner receives from the CAISO for wheeling					
20	service, usage charges, and auctions of firm					
21	transmission rights as well as any other over or					
22	under recoveries associated with the non-load-					
23	serving Participating TO's Transmission Revenue					
24	Requirement (TRR). The TRBAA is a mechanism for					
25	ensuring that amounts in the TRBA are flowed					
26	through to transmission customers.					
27						
28	Energy Data Request Program Memorandum Account	11,744	234,757	Various	25,970	220,531
29	The purpose of the EDRPMA is to record SCE's incre-					
30	mental operation and maintenance (O&M) expenses					
31	and capital-related revenue requirements associated					
32	with the provision of access to energy usage and					
33	usage-related data to local government entities,					
34	researchers, and state and federal agencies,					
35	pursuant to Ordering Paragraph 13 of D.14-05-016.					
36						
37	Mobilehome park Master Meter Balancing Account	29,990	637,029	Various	30,224	636,795
38	The purpose of the Mobilehome Park Master Meter					
39	Balancing Account (MMMBA) is to record actual					
40	incremental incurred costs of implementing the					
41	voluntary program to covert the electric master-					
42	meter/submeter service to direct service at					
43	Mobilehome Parks (MHP) and manufactured housing					
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	communities, pursuant to Decision (D.) 14-03-021.					
2						
3	Post Employment Benefits Other than Pensions		44,320,648	Various	44,320,648	
4	(PBOP) Costs Balancing Account					
5	'To record the difference between PBOP costs					
6	authorized by the Commission, and recorded PBOP					
7	expenses.					
8						
9	Exchange Energy		418,532	407	418,532	
10	To record non-cash related energy costs not					
11	involving the transfer of cash between SCE and					
12	third parties.					
13						
14	Greenhouse Gas Administrative Cost		416,641	254	416,641	
15	Memorandum Account					
16	To record costs associated with initial and ongoing					
17	administrative activities necessary for the					
18	implementation of the GHG allowance revenue					
19	allocation methodology.					
20						
21	Electric Procurement Investment Charge		118,501	Various	118,501	
22	Balancing Account - CPUC					
23	Record authorized EPICBA-CPUC revenue requirements					
24	and authorized payments to the CPUC.					
25						
26	Litigation Costs Tracking Account		10,096,662	407	3,838,089	6,258,573
27	In accordance with Resolution E-3894, SCE shall					
28	maintain a Litigation Costs Tracking Account within					
29	the ESMA to track: 1) litigation costs that are					
30	“set-aside” in the FERC investigation settlement					
31	agreements; and 2) actual litigation costs incureed					
32	by SCE. Amounts recorded in the Litigation Costs					
33	Tracking Account shall be subject to audit in SCE's					
34	ERRA proceedings.					
35						
36	Nuclear Fuel Cancellation Incentive Memorandum		2,275,878	407	17,262	2,258,616
37	Account					
38	The purpose is to apply the incentive mechanism					
39	consistent with Section 4.7 (c) (ii) of the					
40	Settlement, by recording the difference between					
41	nuclear fuel contracts obligation as of January 31					
42	2012 and nuclear fuel cancellation costs					
43	pursuant to D.14-11-040.					
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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						
2	Net Energy Metering (NEM) Online Application		907,401			907,401
3	System Memorandum Account					
4	To track the costs SCE incurs to establish an					
5	online application system for processing					
6	applications for interconnection under SCE's					
7	NEM tariffs, pursuant to Decision (D.)14-11-001.					
8						
9	Residential Energy Disconnections Memorandum		17,841,228	Various	17,814,726	26,502
10	Accounts					
11	To record costs associated with implementation					
12	of the new practices and any uncollectibles					
13	exceeding authorized.					
14						
15	Green Tariff Shared Renewables Admin Cost		77,144			77,144
16	Memorandum Account					
17	To record the difference between revenues collected					
18	through GTSR adminstrative charge and initial					
19	and on-going incremental administratiive costs.					
20						
21	Green Tariff Marketing, Education & Outreach		31,644			31,644
22	Memorandum Account					
23	To record the difference between revenues					
24	collected through Green Tariff ME&O costs and					
25	initial and on-going incremental ME&O costs.					
26						
27	Edison SmartConnect® Opt-Out Balancing Account		7,646,601	Various	866,375	6,780,226
28	To record the difference between the revenues					
29	collected from customers that opt-out of a wireless					
30	smart meter and the costs incurred resulting from					
31	this opt-out election, excluding related exit-fee .					
32						
33	Statewide Marketing Education & Outreach		9,448,141	254	9,448,141	
34	Balancing Account					
35	To record the difference between Commission					
36	-authorized Statewide Marketing, Education &					
37	Outreach funding and recorded expenses.					
38						
39						
40						
41						
42						
43						
44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Department of Energy Litigation Memo Account	705,882	1,156,412	419	76	1,862,218
2	To record: (1) SCE's incremental litigation-related					
3	costs; and (2) proceeds received by SCE from the					
4	federal government for breaching certain Standard					
5	Contracts between SCE and DOE for DOE to dispose of					
6	San Onofre Nuclear Generating Station (SONGS) spent					
7	nuclear fuel.					
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44	TOTAL	9,176,328,731	12,439,155,952		13,683,809,932	7,931,674,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Prepaid Software License	948,342	4,259,293	Various	1,615,943	3,591,692
2						
3	OWIP - ECS Def Debit	5,691,303	13,100,112	Various	11,852,378	6,939,037
4						
5	Plant Claims Pending	14,399,659	159,916	Various	1,579,591	12,979,984
6						
7	SLU Def Proj Cost	308,922				308,922
8						
9						
10	CARB Admin Fees	603,450	2,071,364	Various	2,020,701	654,113
11	OBF Loan Payment	667,857	2,902,155	Various	3,497,627	72,385
12	Misc Deferred Debits	13,068,455	2,952,777	Various	3,907,715	12,113,517
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46						
47	Misc. Work in Progress	87,765,686				81,691,026
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	123,453,674				118,350,676

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	See Footnote	1,866,874,677	1,181,571,512
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,866,874,677	1,181,571,512
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,866,874,677	1,181,571,512

Notes

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
ELECTRIC:			
190	Amort of Debt Issuance Cost	724,626	901,997
190	Executive Incentive Comp	3,781,910	2,421,841
190	DIT - APS Right of Way	-	-
190	Corp Name Change	-	-
190	Bond Discount Amort	1,004,867	1,053,008
190	Executive Incentive Plan	1,569,614	1,514,751
190	Ins - Inj/Damages Prov	74,372,263	59,625,829
190	Accrued Vacation	19,003,404	18,523,690
190	Ins Res/Casualty Loss	49,972	-
190	Int Capitalized - AFUDC	-	-
190	PBOP 401H Amortization	53,413,524	53,413,524
190	EMS	835,335	1,129,064
190	Amortization of Debt Expense	1,764,994	1,659,914
190	DPV2 ADIT - Abandonment	-	-
190	Decommissioning	466,695,408	392,262,808
190	Balancing Accounts	(1,034,461)	5,763,000
190	CIAC/ITCC	344,067,395	93,832,501
190	Pension & PBOP	27,208,610	19,532,301
190	Property/Non-ISO	16,976,098	16,640,333
190	Regulatory Assets/Liab	20,929,142	16,156,752
190	Temp - Other/Non-ISO	835,511,976	330,557,869
190	Net Operating Losses DTA	-	39,349,904
190	Reclass Acct 282 Debit Bal on Repair Deduction/Non-ISO to 190	-	127,232,426
	Total Electric	1,866,874,677	1,181,571,512

Schedule Page: 234 Line No.: 17 Column: a

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
GAS AND OTHER INCOME:			
190	Audit Rollforward	-	-
190	Balancing Accounts	-	-
190	Temp - Other (Non-Electric)	-	-
	Total Gas and Other Income	-	-
		1,866,874,677	1,181,571,512

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock, no par value	560,000,000		
3	TOTAL_COM	560,000,000		
4				
5	Account 204			
6	Preferred stock - without			
7	Mandatory Redemption Requirements			
8	Cumulative participating			
9				
10	$25 Cumulative Preferred:	24,000,000		
11	4.08% Series		25.00	25.50
12	4.24% Series		25.00	25.80
13	4.32% Series		25.00	28.75
14	4.78% Series		25.00	25.80
15				
16	Preferred Stock - with Mandatory Redemption			
17	Requirements			
18	$100 Cumulative Preferred:	12,000,000	100.00	100.00
19				
20				
21	Preference Stock			
22	No Par Value	50,000,000		
23				
24	Non-Voting and Cumulative			
25	6.500% SERIES D			100.00
26	6.25% SERIES E			1,000.00
27	5.625% SERIES F			2,500.00
28	5.10% SERIES G			2,500.00
29	5.75% SERIES H			2,500.00
30	5.375% SERIES J			2,500.00
31				
32	TOTAL_PRE	86,000,000		
33				
34				
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42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
434,888,104	2,168,054,319					2
434,888,104	2,168,054,319					3
						4
						5
						6
						7
						8
						9
						10
650,000	16,250,000					11
1,200,000	30,000,000					12
1,653,429	41,335,725					13
1,296,769	32,419,225					14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
1,250,000	125,000,000					25
350,000	350,000,000					26
190,004	475,010,000					27
160,004	400,010,000					28
110,004	275,010,000					29
130,004	325,010,000					30
						31
6,990,214	2,070,044,950					32
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Accounts 208 and 209	
2	None	
3		
4	Account 210	
5	Gain on Reacquired Preferred Stock (2008)	1,746,500
6		
7	Miscellaneous Paid-in Capital (Account 211)	
8		
9	Respondent issued 778,150 shares of Common Stock in the form of	
10	a 4% stock dividend to the holders of Original Preferred and	
11	Common Stock on January 5, 1961.	
12		
13	778,150 X 32.875 $25,581,681.25 (Market Value)	
14	778,150 X 12.500 9,726,875.00	15,854,806
15		
16	Respondent recorded this amount ($51,497) as a result of merging	
17	with California Electric Power Co., which in turn had recorded it	
18	in connection with the acquisition of a subsidiary company in 1948.	51,497
19		
20	Respondent issued 7,220,000 shares of Common Stock and 296,769	
21	shares of 4.78% Cumulative Preferred Stock to the respective	
22	holders on December 31, 1963, of California Electric Power Co.	
23	Common and $3 Cumulative Preferred Stock.	
24		
25	Common Stock:	
26	Acquired Book Value - $37,570,757.06	
27	Account 201 (7,220,000 X 4 -1/6) = 30,083,333.33	7,487,424
28		
29		
30	4.78% Cumulative Preferred Stock:	
31	Acquired Book Value - $4,946,150.00	
32	Account 201 (296,769 X $25.00) = 7,419,225.00	-2,473,075
33		
34		
35		
36	Return of money deposited in Trust Fund for redemption of	
37	Cumulative Preferred Stock - 4.88% Series.	10,445
38		
39		
40	TOTAL	702,407,126

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Miscellaneous Paid-in Capital (Account 211) Continued:	
2		
3	Respondent recorded this amount as a result of the conversion	
4	of 12-1/2% convertible subordinated debentures, due 1997.	
5	Amount represents interest foregone by debenture holders	
6	from the interest payment date to the conversion dates.	921,446
7		
8	Issuance of 10,000 shares of Edison International Common Stock under	
9	Edison's 1987 Long-term Incentive Compensation Plan. (1988)	317,500
10		
11	Issuance of 12,500 shares of Edison International Common Stock under	
12	Edison's 1987 Long-term Incentive Compensation Plan. (1989)	492,188
13		
14	Accrued dividend equivalents in connection with the exercise	
15	of stock options to purchase 1,600 shares of Edison International Com-	
16	mon Stock under Edison's 1987 Long-term Incentive Compensation	
17	Plan. (1991)	11,392
18		
19	Edison International capital contribution (1992)	184,500,000
20		
21	Issuance of 1,600 shares of Edison International Common Stock under	
22	Edison's 1992 Directors Incentive Compensation Plan. (1992)	64,228
23		
24	Issuance of 4,935 shares of Edison International Common Stock by	
25	exercising stock options under Edison's 1987 Long-term	
26	Incentive Compensation Plan. (1992)	29,911
27		
28	Difference in market price and option price for stock	
29	option exercise on 12-22-95 under Executive Long-Term	
30	Incentive Plan. (1995)	7,616
31		
32	Transferred to Common Stock Account 201 as a result of	
33	stock split effective June 1, 1993.	-25,230,392
34		
35		
36	Stock Options Exercised (1998)	600,289
37		
38	Edison International Capital Contribution (1998)	153,000,000
39		
40	TOTAL	702,407,126

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Miscellaneous Paid-in Capital (Account 211) Continued:	
2		
3	Performance Shares (2001)	2,473,341
4		
5	Performance Shares (2002)	4,203,885
6		
7	Performance Shares (2003)	-3,806,452
8		
9	Performance Shares (2004)	12,273,434
10		
11	Performance Shares (2005)	20,536,431
12		
13	Stock-Based Compensation (2006)	8,157,333
14		
15	Excess Tax Benefits Related to Stock Based Awards (2006)	17,087,817
16		
17	Reclassification of Shares Purchased for Stock Based Compensation	78,102,459
18	(2002-2006)	
19		
20	Stock Based Compensation (2007)	17,949,511
21		
22	Excess Tax Benefits Related to Stock Based Awards (2007)	28,476,623
23		
24	Stock Based Compensation (2008)	18,468,441
25		
26	Excess Tax Benefits Related to Stock Based Awads (2008)	4,136,174
27		
28	Stock Based Compensation (2009)	12,969,153
29		
30	Excess Tax Benefits Related to Stock Based Awards (2009)	6,670,516
31		
32	Stock Based Compensation (2010)	17,123,627
33		
34	Excess Tax Benefits Related to Stock Based Awards (2010)	3,558,644
35		
36	Stock Based Compensation (2011)	15,547,616
37		
38	Excess Tax Benefits Related to Stock Based Awards (2011)	10,630,927
39		
40	TOTAL	702,407,126

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Miscellaneous Paid-in Capital (Account 211) Continued:	
2		
3	Stock Based Compensation (2012)	17,749,941
4		
5	Excess Tax Benefits Related to Stock Based Awards (2012)	-12,656,585
6		
7	Stock Based Compensation (2013)	15,245,245
8		
9	Excess Tax Benefit Related to Stock Based Awards (2013)	1,668,969
10		
11	Stock Based Compensation (2014)	13,222,400
12		
13	Excess Tax Benefit Related to Stock Based Awards (2014)	19,591,400
14		
15	Stock Based Compensation (2015)	12,966,427
16		
17	Excess Tax Benefit Related to Stock Based Awards (2015)	22,668,074
18		
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40	TOTAL	702,407,126

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	103,156
2		
3	Preferred Stock	1,709,919
4		
5		
6		
7		
8		
9	Preference Stock	
10		
11	6.500% SERIES D	2,577,363
12	6.250% SERIES E	5,957,289
13	5.265% SERIES F	15,401,698
14	5.100% SERIES G	12,972,287
15	5.750% SERIES H	6,272,358
16	5.375% SERIES J	6,419,578
17		
18		
19		
20		
21		
22	TOTAL	51,413,648

Schedule Page: 254 Line No.: 1 Column: a

Discount on Capital Stock (Account 213) at Year end is $583.

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			
2	First and Refunding Mortgage Bonds:			
3	Series 2004B	6.0	525,000,000	4,809,750
4				8,661,850 D
5	Series PV 2000AB	5.0	144,400,000	1,300,000
6				
7	Series 2004F	4.65	300,000,000	1,830,000
8				2,996,350 D
9	Series 2004G	5.75	350,000,000	3,062,500
10				2,657,584 D
11	Series 2005A	5.0	400,000,000	2,896,154
12				132,000 D
13	Series 2005B	5.55	250,000,000	2,341,346
14				732,500 D
15	Series 2005E	5.35	350,000,000	3,062,500
16				168,000 D
17	Series 4CRNRS 05AB	1.875	203,460,000	2,216,307
18				
19	Clark County 2010	1.875	75,000,000	853,468
20				
21	Series 2006A	5.625	350,000,000	3,430,000
22				857,500 D
23	SONGS _2006A	1.375	157,500,000	977,486
24				
25	SONGS_2006B	1.90	38,500,000	325,161
26				
27	SONGS 2006CD	4.25	135,000,000	1,517,000
28				
29	Series 2006E	5.55	400,000,000	4,000,000
30				2,176,000 D
31	Series 2008A	5.95	600,000,000	2,760,000 D
32				6,350,000
33	TOTAL		11,392,134,000	166,011,573

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	First and Refunding Mortgage Bonds			
2	Account 221 Continued:			
3				
4	Series 2008B	5.50	400,000,000	2,272,000 D
5				3,250,000
6	Series 2009A	6.05	500,000,000	4,095,000 D
7				4,375,000
8	Series 2010A	5.50	500,000,000	6,015,000 D
9				5,350,000
10	Series 2010B	4.50	500,000,000	3,180,000 D
11				5,325,000
12	SONGS 2010A	4.50	100,000,000	2,000,000
13				
14	2011A	3.875	500,000,000	2,885,000 D
15				4,285,000
16	2011E	3.900	250,000,000	1,405,000 D
17				2,712,500
18	2012A	4.050	400,000,000	4,728,000 D
19				4,300,190
20	2013A	3.900	400,000,000	2,388,000 D
21				4,321,820
22	2013C	3.500	600,000,000	1,056,000 D
23				5,213,033
24	2013D	4.650	800,000,000	5,504,000 D
25				8,347,631
26	2014B	1.125	400,000,000	128,000 D
27				2,422,695
28	2014C	1.250	100,000,000	184,000 D
29				590,000
30	2015A	1.845	550,000,000	D
31				4,303,436
32				
33	TOTAL		11,392,134,000	166,011,573

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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 Continued:			
2	2015B	2.400	325,000,000	22,750 D
3				2,556,738
4	2015C	3.600	425,000,000	1,632,000 D
5				4,562,667
6	4CRNRS 2011	1.875	55,540,000	579,653
7				381,004 D
8	CPCFA SONGS 2011	Variable	30,000,000	350,000
9				
10				
11	SUBTOTAL Account 221		11,114,400,000	160,834,573
12				
13	Account 222			
14				
15	CPCFA SONGS 2011	Variable	-30,000,000	350,000
16				
17	SUBTOTAL- Account 222		-30,000,000	350,000
18				
19	Account 224-Other Long-Term Debt:			
20				
21	6.65% Notes	6.650	300,000,000	1,212,000
22				3,615,000 D
23	Ft. Irwin Loan	5.06	7,734,000	
24				
25	Capitalized Interest Related to Nuclear Fuel			
26	SUBTOTAL- Account 224		307,734,000	4,827,000
27				
28				
29				
30				
31				
32				
33	TOTAL		11,392,134,000	166,011,573

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
01/14/04	01/15/34	01/14/04	01/15/34	525,000,000	31,500,000	3
						4
03/01/04	06/01/35	03/01/04	06/01/35	144,400,000	7,220,000	5
						6
03/23/04	04/01/15	03/23/04	04/01/15		3,487,500	7
						8
03/23/04	04/01/35	03/23/04	04/01/35	350,000,000	20,125,000	9
						10
01/19/05	01/15/16	01/19/05	01/15/16		2,000,000	11
						12
01/19/05	01/15/36	01/19/05	01/15/36	250,000,000	13,875,000	13
						14
06/27/05	7/15/35	6/27/05	07/15/35	350,000,000	18,725,000	15
						16
04/01/15	04/01/29	04/01/15	04/01/29	203,460,000	4,323,525	17
						18
04/01/15	06/01/31	04/01/15	06/01/31	75,000,000	1,054,688	19
						20
01/31/06	02/01/36	01/31/06	02/01/36	350,000,000	19,687,500	21
						22
04/05/13	04/01/28	04/05/13	04/01/28	157,500,000	2,165,625	23
						24
04/05/13	04/01/28	04/05/13	04/01/28	38,500,000	731,500	25
						26
04/12/06	11/01/33	04/12/06	11/01/33	135,000,000	5,737,500	27
						28
12/11/06	01/15/37	12/11/06	01/15/37	400,000,000	22,200,000	29
						30
01/22/08	02/01/38	01/22/08	02/01/38	600,000,000	35,700,000	31
						32
				10,651,796,520	472,179,700	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	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
08/18/08	08/15/18	8/18/08	08/15/18	400,000,000	22,000,000	4
						5
03/20/09	03/15/39	03/20/09	03/15/39	500,000,000	30,250,000	6
						7
3/11/10	03/15/40	03/11/10	03/15/40	500,000,000	27,500,000	8
						9
08/30/10	09/01/40	08/30/10	09/01/40	500,000,000	22,500,000	10
						11
09/21/10	09/01/29	9/21/10	09/01/29	100,000,000	4,500,000	12
						13
05/17/11	06/01/21	05/17/11	06/01/21	500,000,000	19,375,000	14
						15
11/22/11	12/01/41	11/22/11	12/01/41	250,000,000	9,750,000	16
						17
03/13/12	03/15/42	03/13/12	03/15/42	400,000,000	16,200,000	18
						19
03/07/13	03/15/43	03/07/13	03/15/43	400,000,000	15,600,000	20
						21
10/02/13	10/01/23	10/02/13	10/01/23	600,000,000	21,000,000	22
						23
10/02/13	10/01/43	10/02/13	10/01/43	800,000,000	37,200,000	24
						25
05/09/14	05/01/17	05/09/14	05/01/17	400,000,000	4,500,000	26
						27
11/07/14	11/01/17	11/07/14	11/1/17	100,000,000	1,250,000	28
						29
01/26/15	02/01/22	01/26/15	02/01/22	510,714,286	9,422,679	30
						31
						32
				10,651,796,520	472,179,700	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
01/26/15	02/01/22	01/26/15	02/01/22	325,000,000	7,475,000	2
						3
01/26/15	02/01/45	01/26/15	02/01/45	425,000,000	14,662,500	4
						5
04/01/15	04/01/29	04/01/15	04/01/29	55,540,000	781,031	6
						7
09/01/99	09/01/31	09/01/99	09/01/31	30,000,000		8
						9
						10
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	10,375,114,286	452,499,048	11
						12
						13
						14
09/01/11	09/01/31	09/01/11	09/01/31	-30,000,000		15
						16
				-30,000,000		17
						18
						19
						20
04/01/99	04/01/29	04/01/99	04/01/29	300,000,000	19,950,000	21
						22
09/01/03	09/01/53	09/01/03	09/01/53	6,682,234	339,716	23
						24
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx		-609,064	25
				306,682,234	19,680,652	26
						27
						28
						29
						30
						31
						32
				10,651,796,520	472,179,700	33

Schedule Page: 256 Line No.: 2 Column: a

NOTES TO PAGE 256-257A

(1) All mortgage bonds are secured by utility plant, substantially all of which is subject to a lien under the trust indentures. Additional First and Refunding Mortgage Bonds, including additional bonds equal in principal amount to bonds retired, may be issued subject to the provisions of the applicable trust indentures. Each of the bond indentures requires special deposits with the trustees, which are based primarily upon the amount of bonds outstanding. These deposit requirements were satisfied by property additions and replacements.

(2) Maturities and sinking fund requirements of long-term debts for the five years subsequent to December 31, 2015 will be: $0 for 2016; $500 for 2017; $400 for 2018; $0 for 2019; $0 for 2020.

(3) Reacquisition expenses associated with long-term debt issues reacquired prior to maturity, including unamortized premium, discount and issuance expense pertaining to the retired indebtedness are amortized over the remaining lives of the retired indebtedness when reacquired without refunding and over the lives of the new debt issues when reacquired with refunding.

(4) During 2015, respondent capitalized a portion of interest expense on long-term debt for the purpose of financing the Company's nuclear fuel inventory. For 2015 the capitalized interest related to nuclear fuel totaled $609,064.

(5) Bond Series 2004F for $300M retired on 04/01/2015 and Bond Series 2005A for $400M was retired on 02/07/2015. Bond Series 2014A retired on 01/26/2015. 2014A was a short-term debt, therefore, its expense was excluded from long-term debt expenses.

Reconciliation of interest Expense on long-term debt:

Account 427 - 472,179,700

472,179,700

____

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____

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	1,111,055,146
2		
3		
4	Taxable Income Not Reported on Books	
5		1,084,856,393
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		2,284,136,053
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		51,742,186
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		4,428,305,406
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 1 Column: b

Book Income/(loss) - Pre Tax	$1,617,744,306
CA State tax expense	136,834,006
Other state tax expense	990,859
Federal Tax Expense	368,864,295
Net income/(loss) per FERC Form 1 (pg. 117 - Col C, Line 71)	1,111,055,146

Schedule Page: 261 Line No.: 5 Column: b

Taxable Income Not Recorded on Books: (1)
M1 (Line 1)

CIAC/ITCC	215,193,131
Balancing Accounts	869,663,262
	1,084,856,393

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted for Return: (2)
M1 (Line 2)

Book Depreciation	1,691,722,287
Capitalized Software	115,651,668
Decommissioning	15,999,798
Audit Rollforwards	10,273,627
Pension and PBOPs	14,880,690
Federal Tax Expense/(Benefit)	368,864,295
Regulatory Assets/Liab	56,815,290
SONGS Asset Impairment	9,928,398
	2,284,136,053

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded on Books Not Included in Return: (3)
M1 (Line 3)

AFUDC Equity/Debt	51,742,186
	51,742,186

Schedule Page: 261 Line No.: 20 Column: b

Deductions on Return Not Charged Against Book Income: (4)
M1 (Line 4)

Tax Depreciation	1,896,375,930
Repair Deduction	911,278,061
Removal Costs	531,767,628
Gain/(Loss) on Disposition	18,296,311
Temporary - Others	159,450,850
Permanent - Others	24,355,974
CCFT Lag - Electric Current Year	(137,824,865)
State and Local Tax	99,541,091
NOL - Fed	925,064,426

4,428,305,406

Schedule Page: 261 Line No.: 28 Column: b

Federal Tax Net Income = $0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL TAXES:					
2						
3	Federal Income Taxes	-104,912		20,663,284		-17,131,352
4	Tax Reserve - Regulatory	137,998,214		-113,305,850		32,495,070
5	Income Taxes	26,892,624				-25,654,728
6	Fed Ins Cont Act- Current	3,841,541		109,707,572	-109,729,457	-2,524,678
7	Fed Ins Cont Act- Prior					
8	FICA/OASDI Emp Incntv	14,229,103		-4,948,599		
9	FICA/HIT Emp Incntv	3,080,499		-947,192		
10	Fed Unemp Tax Act-Current	5,353,379		2,626,754	-2,040,700	-4,048,822
11	Superfund Tax					
12	FedInsContAct-CurrSONGS			4,129,495	-4,129,495	
13						
14	SUBTOTAL- FED TAXES :	191,290,448		17,925,464	-115,899,652	-16,864,510
15						
16	STATE TAXES :					
17	CA Corp. Franchise Tax	31,446,836		97,440,292	-142,500,000	22,842,916
18	Income Tax- Arizona	-2,074,225			-1,880,587	2,870,891
19	Income Tax- New Mexico					
20	Income Tax- Utah and					
21	Income Tax- DC					
22						
23	Empl Tax-Arizona-Current					
24	CA SUI Current	132,794		6,479,188	-6,505,389	1,129,196
25	CA ET- Current					
26	SUI Florida-Current (EME)					
27	SUI Missouri					
28	SUI R.I. (Source)					
29	SUI WI					
30	EMOM MN SUI TAX					
31	SUI Mass- Current (EC)					
32	SOURCE KY SUI TAX					
33	ENOM NM SUI TAX					
34	ENOM IA SUI TAX					
35	ED. SUPPLY NV SUI TAX					
36	SUI TAX - NEVADA	109,168		-107,672	-1,378	
37	NV SUI TAX (SOURCE)					
38	SUI NEVADA - CURRENT					
39	SUI New York-Current					
40	SUI Texas- EMOM					
41	TOTAL	250,456,644	-11,843,231	425,874,427	-613,631,007	30,847,953

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	SUI Texas- Current					
2						
3	SUI OK- Current (EC)					
4	SUI OR-Current (Source)					
5	SUI Virginia-Current					
6	STATE TAXES (cont):					
7	ACCD SUI TAX - WASH D.C.					
8	D.C. SUI TAX -EME	18		504	-522	
9	SUI Tax DC-Current					
10	SUI W. Vir-Current(EME)					
11	HOMER CITY PA SUI					
12	EME FS. PA SUI TAX					
13	EMMT PA SUI TAX					
14	PA SUI TAX MOMI					
15	SUI Pennsylvania-Current					
16	MWG IL SUI TAX					
17	MG EME IL SUI TAX					
18	EME SERVICES IL SUI TAX					
19	EMMT IL SUI TAX					
20	SUI ILLINOIS MEC					
21	SUI Illinois-Current(Source)	-55		55		
22	SUI Georgia-Current(Source)					
23	SUI NJ-Current(Source)					
24	NY SUI TAX - EMMT					
25	SUI Colo-Current(Source)					
26	SUI Hawaii- Current(Source)					
27	SUI Idaho- Current (Source)					
28	SUI N Mex-Current(Source)					
29	SUI Wash-Current(Source)					
30	WY SUI TAX - EMOM					
31	SUI Wyoming-Current					
32	SUI MI-Current(Source)					
33	SUI South Carolina					
34	SUI CT (Select)					
35	SUI IA O&M					
36	SUI IAX					
37	MA Hlth INS TX - EMMT					
38	SF Pyrl Exp Tx - SCE	154,614		-148,883	-5,058	
39	EMG Pyrl Tax Pay Recl					
40	CADI Vol Plan Assess	238,576		1,616,336	-1,656,850	
41	TOTAL	250,456,644	-11,843,231	425,874,427	-613,631,007	30,847,953

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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						
2	Use Tax-Arizona-Prior					
3						
4	Use Tax-Arizona-Current					
5	Use Tax-California-Prior					
6	Use Tax-California-Current	133,023		1,373,451	-1,390,594	
7	Use Tax-New Mexico-Prior					
8	SALES TAX ACCRUED -	29,644,434		16,446,741	-59,938,338	20,663,363
9	Sales Tax Payable - CA	575		25,918	-8,577	
10	Sales Tax Payable - District					
11	Sales Tax-O&M Services					
12	Accrued District/Local use CA	16,136		22,386	-24,687	122
13	Other Taxes Payable	-630,329			-638,589	
14	Sales Tax Accrued/ Contra					
15						
16	SUBTOTAL-STATE TAXES:	59,171,565		123,148,316	-214,550,569	47,506,488
17						
18	LOCAL TAXES:					
19						
20	Property Tax-Ariz Current			7,819,181	-9,384,373	1,565,192
21	Property Tax-Ariz Prepaid		-1	1,565,077		-1,565,192
22	Property Tax-Calif Current			216,896,967	-271,334,097	54,437,130
23	Property Tax-Calif Prepaid		-11,837,174	56,549,087	568	-54,436,224
24	Property Tax-D.C. Current					
25	Property Tax-Nevada Current			1,646,836	-2,520,091	873,255
26	Property Tax-Nevada Prepaid		-6,056	285,596	57,207	-635,652
27	Property Tax-N Mex Current	-37,903		37,903		
28	Property Tax-N Mex Prepaid					
29	Accrued Tax Liab.Not					
30	Charged to Inc.					
31	Hazardous Waste	32,534				-32,534
32	Use Tax-Nevada-Prior					
33	Use Tax-Nevada-Current					
34	Use Tax-LA County-Prior					
35	Use Tax- LA County Current					
36	Use Tax-Nuclear Fuel					
37	Bus. Activity Tax - Navajo					
38	rounding/adj					
39	SUBTOTAL- LOCAL TAXES	-5,369	-11,843,231	284,800,647	-283,180,786	205,975
40						
41	TOTAL	250,456,644	-11,843,231	425,874,427	-613,631,007	30,847,953

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 (I) 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
						2
3,427,020		20,663,284				3
57,187,434		-10,034,669			-103,271,181	4
1,237,896						5
1,294,978		109,421,774			285,798	6
						7
9,280,504		-3,034,903			-1,913,696	8
2,133,307		-810,922			-136,270	9
1,890,610		2,174,674			452,080	10
						11
		4,129,495				12
						13
76,451,749		122,508,733			-104,583,269	14
						15
						16
9,230,044		119,715,770			-22,275,478	17
-1,083,921						18
						19
						20
						21
						22
						23
1,235,789		6,472,070			7,118	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
118					-107,672	36
						37
						38
						39
						40
91,727,467	-10,022,763	510,173,967			-84,299,540	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) 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
						2
						3
						4
						5
						6
						7
					504	8
						9
						10
						11
						12
						13
						14
						15
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					55	21
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						30
						31
						32
						33
						34
						35
						36
						37
673		20,584			-169,467	38
						39
198,062		1,642,075			-25,739	40
91,727,467	-10,022,763	510,173,967			-84,299,540	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) 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
						2
						3
						4
						5
115,880					1,373,451	6
						7
6,816,200					16,446,741	8
17,916					25,918	9
						10
						11
13,957					22,386	12
-1,268,918						13
						14
						15
15,275,800		127,850,499			-4,702,183	16
						17
						18
						19
		7,786,324			32,857	20
	-115	1,555,474			9,603	21
		198,023,911			18,873,056	22
	-9,723,743	51,781,434			4,767,653	23
						24
		475,336			1,171,500	25
	-298,905	154,353			131,243	26
		37,903				27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
-82						38
-82	-10,022,763	259,814,735			24,985,912	39
						40
91,727,467	-10,022,763	510,173,967			-84,299,540	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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							
7		102,269,658	410/411		410/411	5,352,711	-3,580,996
8	TOTAL	102,269,658				5,352,711	-3,580,996
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
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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
			6
93,335,951	-11		7
93,335,951			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			23
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			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Advance on Jobbing Accounts	81,337,549	Various	13,725,356	28,097,268	95,709,461
2						
3	Accrued Tax Liabilities - LT	75,011,162	Various	61,597,214		13,413,948
4						
5	Miscellaneous Work In Progress	643,648,916	Various	274,865,205	283,475,152	652,258,863
6						
7	Lease Payable - Long-Term	16,382,534	Various	5,865,964	1,256,068	11,772,638
8						
9	Income Tax Component of	122,499,717	Various	460,815,076	479,363,900	141,048,541
10	Contributions in Aid of					
11	Construction					
12						
13	Environmental Remediation	111,155,266	Various	23,878,194	47,294,776	134,571,848
14						
15	TDBU Collateral	34,339,270	Various	14,302,049	21,855,000	41,892,221
16						
17	Deferred Revenue	57,153,809	Various	3,603,425	376,825	53,927,209
18						
19	Unearned Revenue - Bill Advance	58,333	Various	777,283	718,950	
20						
21	Miscellaneous:					
22	Deferred Credits	141,101,049	Various	3,574,727,281	3,580,080,902	146,454,670
23						
24	Intercompany Executive Compen-	112,669,268	Various	30,128,707	22,622,621	105,163,182
25	sation Plan					
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	1,395,356,873		4,464,285,754	4,465,141,462	1,396,212,581

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
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							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	9,082,073,437	3,771,173,529	3,298,604,225
3	Gas	532,077	104,010	
4	Other	7,255,805	1,767,255	122,048
5	TOTAL (Enter Total of lines 2 thru 4)	9,089,861,319	3,773,044,794	3,298,726,273
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	9,089,861,319	3,773,044,794	3,298,726,273
10	Classification of TOTAL			
11	Federal Income Tax	9,089,861,319	3,773,044,794	3,298,726,273
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
		Various	99,621,699			9,455,021,042	2
						636,087	3
						8,901,012	4
			99,621,699			9,464,558,141	5
							6
							7
							8
			99,621,699			9,464,558,141	9
							10
			99,621,699			9,464,558,141	11
							12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 9 Column: k

FERC ACCOUNT	DESCRIPTION	FORM 1 BEG BAL	FORM 1 END BAL
Electric:			
282	Fully Normalized Deferred Tax	(1,218,442,166)	(1,280,768,334)
282	Acc Def Inc Tax-AFUDC	0	0
282	Repair Method Changes - FERC	(30,987,972)	(18,809,474)
282	Fully Normalized Deferred Tax - Book	0	0
282	Franchise Requirements	0	0
282	Property/Non-ISO	(7,110,681,386)	(7,787,494,601)
282	Chino Hills Abandonment	(5,431,095)	0
282	Repair Deduction/Non-ISO	(152,801,131)	0
282	Temp - Other	(363,796,582)	(365,924,689)
282	Capitalized Software	(195,056,467)	(1,822,168)
282	Audit Rollforward	(4,876,639)	(201,776)
	Total Electric	(9,082,073,437)	(9,455,021,042)
Gas:			
282	Property/Non-ISO	(532,077)	(636,087)
	Total Gas	(532,077)	(636,087)
Other:			
282	Property/Non-ISO	(7,255,805)	(8,901,012)
282	Capitalized Software	0	0
282	Temp - Other	0	0
	Total Other	(7,255,805)	(8,901,012)
	Total 282	**(9,089,861,319)**	**(9,464,558,141)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	See Detail Attached	1,398,960,513	131,263,402	746,300,664
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,398,960,513	131,263,402	746,300,664
10	Gas			
11	See Detail Attached	21,780	6,655	12,025
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	21,780	6,655	12,025
18	Other (See Detail Attached)	565,075	142,100	3,814
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,399,547,368	131,412,157	746,316,503
20	Classification of TOTAL			
21	Federal Income Tax	1,399,547,368	131,412,157	746,316,503
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		Various	-9,130,841			793,054,092	3
							4
							5
							6
							7
							8
			-9,130,841			793,054,092	9
							10
						16,410	11
							12
							13
							14
							15
							16
						16,410	17
						703,361	18
			-9,130,841			793,773,863	19
							20
			-9,130,841			793,773,863	21
							22
							23

NOTES (Continued)

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

FERC ACCT	Description	FF1 Balance at Beg of Year	FF1 Balance at End of Year
ELECTRIC:			
283	Def Tax State - Other (GSI)	-	-
283	Payroll Tax	-	-
283	Ad Valorem Lien Date Adj-Electric	(72,795,941)	(81,776,003)
283	State Rate Adjustment	-	-
283	Refunding & Retirement of Debt	(68,983,269)	(69,744,052)
283	Health Care - IBNR	(2,121,525)	(1,343,194)
283	Balancing Accounts	(552,974,862)	(198,633,893)
283	Capitalized Software	-	-
283	Decommissioning	(440,824,636)	(359,836,108)
283	Property/Non-ISO	-	-
283	Repair Deduction	-	-
283	Regulatory Assets/Liab	(23,738,798)	(3,811,581)
283	Temp - Other/Non-ISO	(237,521,482)	(77,909,261)
	TOTAL ELECTRIC	(1,398,960,513)	(793,054,092)

Schedule Page: 276 Line No.: 11 Column: k

FERC ACCT	Description	FF1 Balance at Beg of Year	FF1 Balance at End of Year
GAS & OTHER INCOME			
283	Balancing Accounts	(12,025)	-
283	Property/Non-Electric	-	-
283	Temp - Other/Non-Electric	(9,755)	(16,410)
	Total Gas	**(21,780)**	**(16,410)**

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

FERC ACCT	Description	FF1 Balance at Beg of Year	FF1 Balance at End of Year
283	Capitalized Software/Non-ISO	-	-
283	Property/Non-Electric	-	-
283	Temp - Other/Non-Electric	(565,075)	(703,361)
283	Account recode from 190 to 283	-	-
	Total Other	**(565,075)**	**(703,361)**
	Total Account 283.xxx/25310xx - 25350xx	**(1,399,547,368)**	**(793,773,863)**

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Research Development and Demonstration	3,763	Various	2,362,367	2,358,604	
2	Balancing Account					
3	To track Commission authorized funding and re-					
4	cord the difference between revenues and costs					
5	associated with RD&D.					
6						
7	Demand Reduction and Self-Generation Program	196,456,361	Various	22,009,450	28,293,401	202,740,312
8	To track the recorded incremental program costs					
9	and requirement recorded in the Base Revenue					
10	requirement Balancing Account (BRRBA) associated					
11	with SCE's Small Commercial Demand responsiveness					
12	Pilot Program and the Self-Generation Pilot					
13	Program authorized by the CPUC.					
14						
15	Energy Savings Assistance Program (Formerly Low	87,917,336	Various	51,176,408	72,884,510	109,625,438
16	Income Program Adjustment Mechanism)					
17	To track the Public Purpose Program Charge Funds					
18	allocable to the 1998 low income programs and the					
19	1998 low income energy efficiency program					
20	expenses.					
21						
22	Electric Deferred Refund Account	7,460,221	182	7,462,521	7,729,556	7,727,256
23	To record credits for electric disallowances					
24	ordered by the Commission, Utility Electric					
25	Generation (UEG) shares of gas disallowances					
26	ordered by the Commission or FERC and electric					
27	and UEG amounts resulting from the settlement of					
28	reasonableness disputes at the Commission or FERC					
29						
30						
31	Procurement Energy Efficiency Balancing Acct.	229,477,469	Various	379,991,679	302,761,182	152,246,972
32	To track the difference between actual incremen-					
33	tal procurement-related energy efficiency costs					
34	and authorized procurement-related energy					
35	efficiency revenues per D.03-12-062.					
36						
37	Asset Retirement Obligation (ARO)	1,955,925,951	Various	1,347,123,794	893,600,176	1,502,402,333
38	To establish a regulatory liability for					
39	decommissioning costs collected in rates					
40	for ARO assets.					
41	TOTAL	3,743,734,429		8,802,554,750	9,161,945,065	4,103,124,744

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 Account Credited	DEBITS Amount	Credits	Balance at End of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Transmission Rev Balancing Acct Adjustment		Various	37,339,865	60,512,383	23,172,518
3	To record transmission revenue credits,Congestion					
4	revenue, wheeling revenue, sale of an FTR revenu,					
5	and ancillary service expense to the TRBAA.					
6						
7	Energy Resource Recovery Account		Various	115,206,074	480,432,574	365,226,500
8	To record SCE's ERRA Revenue, Utility Retained					
9	Generation fuel costs, and purchased power					
10	related expenses.					
11						
12	Miscellaneous Regulatory Liability	32,584,089	Various	43,444,700	44,223,907	33,363,296
13	To capture various accrued purchased power					
14	agreements and other miscellaneous regulatory					
15	liabilities.					
16						
17	Demand Response Program Balancing Account (DRPBA)	129,616,822	Various	31,054,868	73,430,885	171,992,839
18	To record the difference between the actual					
19	capital related revenue requirement and O&M costs					
20	incurred by SCE and the authorized Demand					
21	Response Revenue Requirement approved by the					
22	Commission in D.06-03-024 and in SCE's					
23	General Rate Case (GRC) proceedings.					
24						
25	California Solar Inititative Program	171,730,340	Various	82,708,916	97,772,570	186,793,994
26	Balancing Account					
27	To track the recorded incremental California					
28	Solar Initiative Program costs and authorized					
29	distribution revenue requirement recorded in the					
30	Base Revenue Requirement Balancing Account					
31	(BRRBA) associated with SCE's California					
32	Solar Initiative Program.					
33						
34	Post Employment Benefits Other than Pensions	25,251,792	Various	37,825,368	24,016,256	11,442,680
35	(PBOP) Costs Balancing Account					
36	To record the difference between PBOP costs					
37	authorized by the Commission, and recorded					
38	PBOP expenses.					
39						
40						
41	TOTAL	3,743,734,429		8,802,554,750	9,161,945,065	4,103,124,744

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Affiliate Transfer Memorandum Account	223,923	254	223,923	1,742	1,742
2	To record transfer fees received from affiliates					
3	when an employee is transferred, assigned, or					
4	otherwise employed by the affiliate.					
5						
6	WECC Statutory Costs	7,707,203	407	7,707,203	8,261,534	8,261,534
7	To record WECC statutory fees being amortized					
8	over 12-month period.					
9						
10	Purchase Agreement Administrative Costs Balancing	762,019	Various	221,319	701,503	1,242,203
11	Account					
12	To record the difference between SCE's actual					
13	and authorized administrative costs associated					
14	with the Aggregator Managed Portfolio Program in					
15	accordance with D.08-03-017, D.09-08-027,					
16	D13-01-024 and D.14-05-025.					
17						
18	Energy Efficiency Finance Programs Balancing Acct	74,648,341	Various	14,820,177	22,920,843	82,749,007
19	(OBFBA Previously)					
20	To record the difference between actual and					
21	authorized revenue for OBF loan funding, EE Fin-					
22	ance Pilots and ARRA program credit enhancements					
23	in accordance with D.14-10-046.					
24						
25	Medical Balancing Account	14,166,414	Various	83,935,635	94,557,927	24,788,706
26	To record the difference between the authorized					
27	and recorded Medical, Dental, Vision expenses in					
28	accordance with D. 09-03-025.					
29						
30	Misc. On-Bill Financing Regulatory Liability	23,962,569	407	2,213,844	3,170,886	24,919,611
31	To offset 2010-2012 and 2013-2014 OBF loans					
32	and loan repayments.					
33						
34	REC Regulatory Liability	9,139,520		3,972,668	8,976,866	14,143,718
35	To record renewable energy credit inventory					
36	as regulatory liability.					
37						
38						
39						
40						
41	TOTAL	3,743,734,429		8,802,554,750	9,161,945,065	4,103,124,744

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	FERC Formula Rate					
2	To record the difference between billed and					
3	unbilled revenue and the recorded transmission					
4	revenue requirement to cover the costs of owning					
5	and operating transmission facilities under					
6	ISO control.					
7						
8	Gross Revenue Sharing Mechanism		254	7,727,255	7,727,255	
9	To record the customers' share of certain Other					
10	Operating Revenue (OOR), as per Advice Letter No.					
11	1413-E-A, dated September 16, 1999.					
12						
13	Electric Program Investment Charge-CEC, SCE	171,288,178	Various	94,811,342	71,590,627	148,067,463
14	and CPUC					
15	To record authorized administrative and program					
16	EPIC revenue requirements and related program					
17	SCE expenses and authorized program payments					
18	to CEC and CPUC per advice letter 2747-E					
19	dated June 25, 2012.					
20						
21	Public Purpose Programs Adjustment Mechanism					
22	To record Public Goods Charge Revenue,					
23	PGC expenses authorized in P. U. Code					
24	Section 399.8 and other CPUC Public					
25	Purpose Program revenues and expenses.					
26						
27	GCAC Balancing Account		Various	65,199	329,789	264,590
28	Balance composed of Gas Cost Adjustment					
29	Clause which recovers/refunds gas costs on					
30	Catalina Island.					
31						
32	Pension Costs Balancing Account	24,861,342	Various	114,202,486	89,341,144	
33	To record the difference between pension costs					
34	authorized by the Commission and recorded					
35	pension expenses.					
36						
37	Exchange Energy	3,062,167	407	3,073,569	11,402	
38	To record non-cash related energy costs not					
39	involving the transfer of cash between SCE					
40	and third parties.					
41	TOTAL	3,743,734,429		8,802,554,750	9,161,945,065	4,103,124,744

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1						
2	Other Regulatory Liability	1,303,627	Various	460,114,751	459,049,695	238,571
3	To record the proceeds from SONGS inventory,					
4	plant and salvage materials from Mesa facility					
5	pending a CPUC final decision and incremental tax					
6	benefit from additional T&D repair deductions.					
7						
8	CARE Balancing Account	20,467,440	Various	51,033,847	51,085,267	20,518,860
9	To reflect in rates, through application of the					
10	Public Purpose Program Charge the costs					
11	associated with the CARE Program as					
12	authorized in various CPUC Decisions.					
13						
14	GHG Revenue Balancing Account	181,763,460	Various	507,453,686	400,283,335	74,593,109
15	To record the difference between the amount of					
16	GHG revenue actually returned to customers via					
17	rates and bill credits and the actual amount of					
18	GHG revenue SCE receives through consigning					
19	allowances to the cap and trade auction.					
20						
21	Statewide ME&O Balancing Account	1,333,092	Various	27,526,600	29,810,921	3,617,413
22	To record the difference between Commission-					
23	authorized Statewide Marketing, Education &					
24	Outreach funding and recorded expenses.					
25						
26	Base Revenue Balancing Account	5,370,535	Various	4,734,470,417	5,047,946,702	318,846,820
27	To record the difference between the commission					
28	authorized base distribution and generation					
29	revenue requirements and the recorded retail					
30	distribution and generation revenues.					
31						
32						
33	Mohave SO2 Allowance Revolving Fund Memo Account	3,595,765			5,307	3,601,072
34	To record the net proceeds from the sale of					
35	sulfurdioxide (SO2) emission allowances					
36	rendered surplus by the closure of the Mohave					
37	Generating Station and to maintain and account					
38	for the revolving fund from the sale and use of					
39	these emission credits.					
40						
41	TOTAL	3,743,734,429		8,802,554,750	9,161,945,065	4,103,124,744

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Project Development Memo Account	6,785,122	407	8,650,757	6,771,557	4,905,922
2	To track the difference between Project Develop-					
3	ment Division (PDD) recorded support costs and					
4	PDD forecast.					
5						
6	Nuclear Decommissioning Adjustment Mechanism	52,883,351	Various	213,769	25,584,896	78,254,478
7	To record NDAM revenue, authorized and					
8	recorded costs related to the decommissioning of					
9	San Onofre Nuclear Generating Station and Palo					
10	Verde Nuclear Generating Station.					
11						
12	San Onofre Regulatory Liability		182		20,845,570	20,845,570
13	To record the difference between San Onofre					
14	Nuclear Generating Station costs and nuclear					
15	decommissioning trust contributions authorized					
16	and recorded expenses.					
17						
18	Energy Settlement Memo Account	197,276,649	Various	204,060,165	11,300,481	4,516,965
19	To record refund amounts received by SCE					
20	resulting from FERC investigation settlement					
21	agreements associated with wholesale power					
22	purchases made on behalf of SCE's bundled service					
23	customers, net of litigation costs recorded					
24	in the litigation Costs Tracking Account.					
25						
26	Reliability Service Balancing Account	98,628,698	Various	105,723,856	7,998,367	903,209
27	To track the RS revenues and RS costs to ensure					
28	that SCE neither over-collects nor under-collects					
29	RS costs assessed.					
30						
31						
32	Results Sharing Memorandum Account					
33	To track the difference between authorized and					
34	recorded Results Sharing expenses paid out.					
35						
36	Financial Reporting Regulatory Liability	7,075,057	407	1,500,000		5,575,057
37	To record financial/regulatory reserves.					
38						
39						
40						
41	TOTAL	3,743,734,429		8,802,554,750	9,161,945,065	4,103,124,744

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Marine Corps Air Ground Combat Center Memo	1,005,813			1,468	1,007,281
2	Account					
3	To track the after-tax gain on sale of certain					
4	distribution assets located at the United States					
5	Marine Corps Air Ground Combat Center,					
6	Twentynine Palms, California.					
7						
8	New System Gen Balancing Account		Various	124,294,185	295,264,949	170,970,764
9	To record the benefits and costs of Power Purchae					
10	agreements (PPAs) and SCE owned peaker generation					
11	unit associated with new generation resources.					
12						
13	SONGS Cost of Financing Balancing Account		407	83,468	1,737,745	1,654,277
14	To track 50% of the savings reflected in the					
15	difference between actual cost of financing and					
16	authorized return on SONGS rate base.					
17						
18	Energy Resource Recovery Account		Various		73,836,000	73,836,000
19	To record SCE's ERRA Revenue, Utility Retained					
20	Generation fuel costs, and purchased power					
21	related expenses.					
22						
23	Pole Loading and Deteriorated Pole		Various	70,939,460	107,120,290	36,180,830
24	Balancing Account (PLDPBA)					
25	To record the difference between recoded capital-					
26	related revenue, operating expenses, and the					
27	authorized revenue requirement authorized by					
28	D.15-11-021.					
29						
30	Tax Accounting Memo Account (TAMA)		Various	15,809,159	227,694,995	211,885,836
31	To track impact on authorized CPUC juris-					
32	dictional revenue requirement as adopted in					
33	D.15-11-021; resulting from income tax accounting					
34	method changes, changes in federal or state law					
35	difference between authorized and recorded					
36	federal and California non-pole loading net					
37	repair deductions, audit findings, or changes					
38	in authorized revenue requirements.					
39						
40	rounding				(2)	-2
41	TOTAL	3,743,734,429		8,802,554,750	9,161,945,065	4,103,124,744

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	4,942,532,983	4,834,758,093
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	6,182,228,424	6,234,933,389
5	Large (or Ind.) (See Instr. 4)	941,274,466	1,007,954,771
6	(444) Public Street and Highway Lighting	115,261,578	112,915,797
7	(445) Other Sales to Public Authorities	11,992,158	11,529,544
8	(446) Sales to Railroads and Railways	12,079,970	12,190,152
9	(448) Interdepartmental Sales	147,254	164,384
10	TOTAL Sales to Ultimate Consumers	12,205,516,833	12,214,446,130
11	(447) Sales for Resale	111,197,753	1,355,811,076
12	TOTAL Sales of Electricity	12,316,714,586	13,570,257,206
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	12,316,714,586	13,570,257,206
15	Other Operating Revenues		
16	(450) Forfeited Discounts	17,677,575	16,974,819
17	(451) Miscellaneous Service Revenues	14,491,027	15,367,008
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	77,474,902	77,162,166
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	460,444,153	449,545,602
22	(456.1) Revenues from Transmission of Electricity of Others	94,897,914	65,965,831
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	rounding	-1	
26	TOTAL Other Operating Revenues	664,985,570	625,015,426
27	TOTAL Electric Operating Revenues	12,981,700,156	14,195,272,632

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
29,961,360	30,043,587	4,381,511	4,358,058	2
				3
46,225,508	46,455,839	589,565	586,990	4
9,447,046	10,344,255	32,250	32,199	5
547,825	549,022	16,427	16,074	6
202,069	202,270	4	4	7
78,959	82,399	117	102	8
704	889	22	22	9
86,463,471	87,678,261	5,019,896	4,993,449	10
4,031,926	28,758,934	17	20	11
90,495,397	116,437,195	5,019,913	4,993,469	12
				13
90,495,397	116,437,195	5,019,913	4,993,469	14

Line 12, column (b) includes $ -67,556,000 of unbilled revenues.
Line 12, column (d) includes -393,000 MWH relating to unbilled revenues

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	NONE.				
2					
3					
4					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	NOTE: See Footnote for Symbols					
2						
3	ACCOUNT 440					
4	D	18,102,393	3,447,385,929	2,690,619	6,728	0.1904
5	D @	30,006	3,023,096	3,595	8,347	0.1007
6	D $	21,225	2,148,224	5,228	4,060	0.1012
7	D-CARE	6,959,494	814,367,136	1,158,806	6,006	0.1170
8	D-CARE @	4,691	93,451	748	6,271	0.0199
9	D-CARE $	17,982	526,424	4,445	4,045	0.0293
10	D-CARE-CPP	3	177	1	3,000	0.0590
11	DCARE-E	4,822	738,201	422	11,427	0.1531
12	DCARE-E $	2	64			0.0320
13	DCARE-E-N	31	5	1	31,000	0.0002
14	D-CARE-N	71,344	3,643,943	9,231	7,729	0.0511
15	D-CARE-N $	412	840	67	6,149	0.0020
16	D-CARE-SDP	613,781	68,366,746	74,985	8,185	0.1114
17	D-CARE-SDP @	1,138	13,840	135	8,430	0.0122
18	D-CARE-SDP $	1,891	62,874	400	4,728	0.0332
19	D-CARE-SDP-N	13,249	538,233	1,564	8,471	0.0406
20	D-CARE-SDP-N$	86	213	6	14,333	0.0025
21	D-CARE-SDP-O	16,283	1,970,059	2,005	8,121	0.1210
22	DCARE-SDP-O @	26	75	4	6,500	0.0029
23	DCARE-SDP-O $	53	1,830	4	13,250	0.0345
24	DCARE-SDP-O-N	361	11,720	47	7,681	0.0325
25	DCARE-SDP-ON$	1	7			0.0070
26	D-DL #		817			
27	DE	89,595	12,818,087	10,913	8,210	0.1431
28	DE $	30	1,875	3	10,000	0.0625
29	DE-FERA	461	62,724	51	9,039	0.1361
30	DE-FERA $	1	40			0.0400
31	DE-FERA-N	19	589	2	9,500	0.0310
32	DE-FERA-SDP	227	31,338	20	11,350	0.1381
33	DE-FERA-SDP-N	14	9	1	14,000	0.0006
34	DE-FERA-SDP-O	33	4,539	2	16,500	0.1375
35	DE-N	1,876	111,965	226	8,301	0.0597
36	DE-S	158	21,807	15	10,533	0.1380
37	DE-SDP	35,912	4,749,014	3,897	9,215	0.1322
38	DE-SDP @	17	628	2	8,500	0.0369
39	DE-SDP $	21	1,270	1	21,000	0.0605
40	DE-SDP-N	675	34,110	80	8,438	0.0505
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	ACCOUNT 440 CONTINUED					
2	DE-SDP-N $	2	12			0.0060
3	DE-SDP-O	898	123,654	105	8,552	0.1377
4	DE-SDP-O-N	8	-77	1	8,000	-0.0096
5	DE-TOU-A	151	17,095	20	7,550	0.1132
6	DE-TOU-A-N	45	70	6	7,500	0.0016
7	DE-TOU-A-SDP	153	13,345	18	8,500	0.0872
8	DETOU-A-SDP-N	76	2,270	6	12,667	0.0299
9	DETOU-A-SDP-O	5	498	1	5,000	0.0996
10	DETOUA-SDPO-N	7	-54	1	7,000	-0.0077
11	DE-TOU-B	466	60,477	38	12,263	0.1298
12	DE-TOU-B-N	10	1,175	1	10,000	0.1175
13	DE-TOU-B-SDP	504	57,417	40	12,600	0.1139
14	DETOU-B-SDP-N	4	243			0.0608
15	DETOU-B-SDP-O	26	3,016	2	13,000	0.1160
16	DE-TOUT	540	87,125	41	13,171	0.1613
17	DE-TOUT-N	72	3,207	9	8,000	0.0445
18	DE-TOUT-SDP	613	93,575	43	14,256	0.1527
19	DETOUTSDP-CPP	13	1,901	1	13,000	0.1462
20	DE-TOUT-SDP-N	179	8,029	16	11,188	0.0449
21	DE-TOUT-SDP-O	15	2,558	1	15,000	0.1705
22	DE-TOUT-SDPON	2	1			0.0005
23	DE-TUTEV	66	8,820	5	13,200	0.1336
24	DE-TUTEV-N	20	1,185	2	10,000	0.0593
25	DE-TUTEV-SDP	91	11,947	6	15,167	0.1313
26	DETUTEV-SDP-N	21	312	2	10,500	0.0149
27	DETUTEV-SDP-O	4	510			0.1275
28	DETUTEVSDP-ON	3	5			0.0017
29	D-FERA	139,529	24,521,754	17,763	7,855	0.1757
30	D-FERA @	83	7,376	10	8,300	0.0889
31	D-FERA $	249	22,176	54	4,611	0.0891
32	D-FERA-N	4,027	259,568	469	8,586	0.0645
33	D-FERA-N $	32	236	2	16,000	0.0074
34	D-FERA-SDP	17,519	2,899,113	1,868	9,378	0.1655
35	D-FERA-SDP @	43	3,594	4	10,750	0.0836
36	D-FERA-SDP $	64	5,443	11	5,818	0.0850
37	DFERA-SDP-CPP	1	223			0.2230
38	DFERASDPCPP-N	1	4			0.0040
39	D-FERA-SDP-N	915	38,725	101	9,059	0.0423
40	D-FERA-SDP-N$	2	12			0.0060
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 440 CONTINUED					
2	D-FERA-SDP-O	758	130,971	85	8,918	0.1728
3	DFERA-SDP-O-N	18	1,305	3	6,000	0.0725
4	DM	86,427	16,632,120	5,445	15,873	0.1924
5	DM @	1,255	113,802	34	36,912	0.0907
6	DM-CARE	1	134			0.1340
7	DM-CARE-E	16	2,431	1	16,000	0.1519
8	DM-CARE-N	2	46			0.0230
9	DM-N	2,088	250,373	107	19,514	0.1199
10	DMS-1	35,344	5,384,636	257	137,525	0.1523
11	DMS-1 @	13	950	1	13,000	0.0731
12	DMS-1-N	1,017	52,181	9	113,000	0.0513
13	DMS-2	494,006	63,431,945	1,444	342,109	0.1284
14	DMS-2 @	1,174	66,064	7	167,714	0.0563
15	DMS-2 $	1,980	130,931	7	282,857	0.0661
16	DMS-2-N	21,465	1,962,258	35	613,286	0.0914
17	DMS-3	12,572	1,991,954	73	172,219	0.1584
18	DMS-3 @	207	5,300	2	103,500	0.0256
19	DMS-3-N	2,203	114,129	2	1,101,500	0.0518
20	D-N	789,622	67,737,369	89,026	8,870	0.0858
21	D-N @	48	1,361	5	9,600	0.0284
22	D-N $	2,061	22,792	455	4,530	0.0111
23	D-PG-S	5	728	1	5,000	0.1456
24	D-S	34,400	6,643,460	3,657	9,407	0.1931
25	D-S @	228	23,012	20	11,400	0.1009
26	D-S $	8	665			0.0831
27	D-S-CARE	3,134	393,661	336	9,327	0.1256
28	D-S-CARE @	39	1,088	4	9,750	0.0279
29	D-S-CARE $	2	34			0.0170
30	D-S-CARE-N	53	3,023	5	10,600	0.0570
31	D-S-CARE-N $	2	-2			-0.0010
32	D-SDP	1,602,354	279,155,057	189,773	8,444	0.1742
33	D-SDP @	6,053	467,070	691	8,760	0.0772
34	D-SDP $	3,149	318,598	648	4,860	0.1012
35	D-SDP-CPP	12	2,061	1	12,000	0.1718
36	D-SDP-CPP-N	7	8	1	7,000	0.0011
37	D-SDP-N	126,034	8,591,423	14,278	8,827	0.0682
38	D-SDP-N @	40	-1,190	3	13,333	-0.0298
39	D-SDP-N $	543	5,687	115	4,722	0.0105
40	D-SDP-O	44,672	8,309,171	5,317	8,402	0.1860
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 440 CONTINUED					
2	D-SDP-O @	84	7,451	11	7,636	0.0887
3	D-SDP-O $	54	5,015	4	13,500	0.0929
4	D-SDP-O-N	3,674	223,909	461	7,970	0.0609
5	D-SDP-O-N $	7	74			0.0106
6	D-S-FERA	37	7,963	2	18,500	0.2152
7	D-S-N	1,701	154,277	158	10,766	0.0907
8	D-S-N $	2	25			0.0125
9	DTA-CARE-SDP	220	21,990	26	8,462	0.1000
10	DTACARE-SDP $	1	58			0.0580
11	DTACARE-SDP-N	59	486	6	9,833	0.0082
12	DTACARE-SDP-O	4	475	1	4,000	0.1188
13	DTACARESDPO-N	6	16			0.0027
14	DTA-SDP-O-N	132	4,521	15	8,800	0.0343
15	DTB-CARE-SDP	706	87,147	56	12,607	0.1234
16	DTBCARE-SDP-N	8	47	1	8,000	0.0059
17	DTBCARE-SDP-O	18	2,285	2	9,000	0.1269
18	DTB-SDP-O-N	43	4,062	3	14,333	0.0945
19	D-TOU-A	15,711	2,378,266	2,115	7,428	0.1514
20	D-TOU-A $	2	236			0.1180
21	D-TOU-A-CARE	919	111,311	121	7,595	0.1211
22	D-TOU-A-CARE$	2	86			0.0430
23	DTOU-A-CARE-N	94	3,020	11	8,545	0.0321
24	DTOU-A-CAREN$	1	9			0.0090
25	D-TOU-A-N	10,360	339,428	1,014	10,217	0.0328
26	D-TOU-A-N $	10	81	1	10,000	0.0081
27	D-TOU-A-SDP	3,404	419,363	420	8,105	0.1232
28	D-TOU-A-SDP @	4	74	1	4,000	0.0185
29	DTOUA-SDP-CPP	6	1,000	1	6,000	0.1667
30	D-TOU-A-SDP-N	2,475	100,275	243	10,185	0.0405
31	D-TOU-A-SDPN$	6	69			0.0115
32	D-TOU-A-SDP-O	112	16,030	14	8,000	0.1431
33	D-TOU-B	52,353	8,865,475	3,469	15,092	0.1693
34	D-TOU-B @	52	4,374	5	10,400	0.0841
35	D-TOU-B $	36	3,278	1	36,000	0.0911
36	D-TOU-B-CARE	1,259	165,920	95	13,253	0.1318
37	D-TOU-B-CARE$	5	284			0.0568
38	DTOU-B-CARE-N	44	5,919	4	11,000	0.1345
39	DTOU-B-CAREN$	3	11			0.0037
40	D-TOU-B-N	3,857	365,740	270	14,285	0.0948
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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1	ACCOUNT 440 CONTINUED					
2	D-TOU-B-N $	3	54			0.0180
3	D-TOU-B-SDP	7,444	1,108,353	555	13,413	0.1489
4	D-TOU-B-SDP @	11	581	1	11,000	0.0528
5	D-TOU-B-SDP $	9	760			0.0844
6	D-TOU-B-SDP-N	887	55,651	58	15,293	0.0627
7	D-TOU-B-SDP-O	296	48,695	22	13,455	0.1645
8	D-TOU-EV-1	2,591	353,703	668	3,879	0.1365
9	D-TOU-EV-1 @	18	1,627	1	18,000	0.0904
10	D-TOU-EV-1 $	2	187	1	2,000	0.0935
11	D-TOU-EV-1-N	4	69	2	2,000	0.0173
12	D-TOUT	61,012	13,923,154	3,915	15,584	0.2282
13	D-TOUT @	79	9,553	6	13,167	0.1209
14	D-TOUT $	30	4,545			0.1515
15	D-TOUT-CARE	14,767	2,526,057	1,098	13,449	0.1711
16	D-TOUT-CARE $	2	124			0.0620
17	D-TOUT-CARE-N	2,118	116,011	244	8,680	0.0548
18	D-TOUT-CPP-N	7	-98	1	7,000	-0.0140
19	D-TOUT-C-SDP	7,844	1,282,652	554	14,159	0.1635
20	D-TOUT-C-SDP$	2	96			0.0480
21	DTOUT-C-SDP-N	1,225	64,571	122	10,041	0.0527
22	DTOUT-C-SDP-O	80	13,401	6	13,333	0.1675
23	DTOUTC-SDPO-N	23	480	3	7,667	0.0209
24	D-TOUT-N	64,079	5,803,747	6,220	10,302	0.0906
25	D-TOUT-N $	45	363	8	5,625	0.0081
26	D-TOUT-SDP	23,823	4,937,545	1,670	14,265	0.2073
27	D-TOUT-SDP @	51	7,086	1	51,000	0.1389
28	D-TOUT-SDP-N	20,630	1,633,069	2,024	10,193	0.0792
29	D-TOUT-SDP-N$	19	164	3	6,333	0.0086
30	D-TOUT-SDP-O	414	90,678	31	13,355	0.2190
31	DTOUT-SDP-O-N	507	36,908	51	9,941	0.0728
32	DTU-TEV	10,048	1,867,584	620	16,206	0.1859
33	DTU-TEV @	1	128			0.1280
34	DTU-TEV-CARE	304	42,308	21	14,476	0.1392
35	DTUTEV-CARE-N	33	1,393	3	11,000	0.0422
36	DTU-TEV-C-SDP	110	15,720	8	13,750	0.1429
37	DTUTEVC-SDP-N	23	387	2	11,500	0.0168
38	DTU-TEV-N	4,152	238,712	285	14,568	0.0575
39	DTU-TEV-SDP	1,951	349,922	129	15,124	0.1794
40	DTU-TEV-SDP @	3	311			0.1037
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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1	ACCOUNT 440 CONTINUED					
2	DTU-TEV-SDP-N	992	54,321	75	13,227	0.0548
3	DTU-TEV-SDP-O	66	12,764	3	22,000	0.1934
4	DTUTEVSDP-O-N	61	563	5	12,200	0.0092
5	DWL-A	1,832	334,943	94	19,489	0.1828
6	DWL-A @	12	1,388	1	12,000	0.1157
7	DWL-B	50	7,614	1	50,000	0.1523
8	DWL-C	101	16,392	2	50,500	0.1623
9	GS-1	3,341	717,650	36	92,806	0.2148
10	GS-1 @	9	1,338	1	9,000	0.1487
11	GS1-APSE	2	476			0.2380
12	GS-1-N	47	6,004	1	47,000	0.1277
13	GS-2	479	76,619	2	239,500	0.1600
14	GS-2 @	58	5,371			0.0926
15	GS-2-N	12	2,426			0.2022
16	OL-1-ALLNITE	2,588	736,025	3,422	756	0.2844
17	OL-1ALLNITE@		115	1		
18	OL-1ALLNITE $			2		
19	PA-1	48	18,224	9	5,333	0.3797
20	PA-1-N	1	119			0.1190
21	PA-2	5	1,411			0.2822
22	TGS1-A	252,143	52,326,003	48,128	5,239	0.2075
23	TGS1-A @	1,876	183,581	213	8,808	0.0979
24	TGS1-A $	237	26,714	54	4,389	0.1127
25	TGS1-A-APSE	209	33,916	17	12,294	0.1623
26	TGS1-A-C	77	9,057	4	19,250	0.1176
27	TGS1-A-CPP	36	6,026	3	12,000	0.1674
28	TGS1-A-CPP-N	-4	-52			0.0130
29	TGS1-A-N	907	89,354	90	10,078	0.0985
30	TGS1-A-N $	2	101			0.0505
31	TGS1-B	33,020	4,542,804	1,908	17,306	0.1376
32	TGS1-B @	1,303	85,780	76	17,145	0.0658
33	TGS1-B $	31	1,954	3	10,333	0.0630
34	TGS1-B-APSE	36	4,740	1	36,000	0.1317
35	TGS1-B-C	13	1,062			0.0817
36	TGS1-B-N	43	1,626	2	21,500	0.0378
37	TGS1-RTP	2	653	1	2,000	0.3265
38	TGS2A-S	3	483			0.1610
39	TGS2B-APSE-S	50	10,368	1	50,000	0.2074
40	TGS2B-C-S	51	4,470	1	51,000	0.0876
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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1	ACCOUNT 440 CONTINUED					
2	TGS2B-N-S	103	26,548	3	34,333	0.2577
3	TGS2B-S	39,227	6,443,972	350	112,077	0.1643
4	TGS2B-S @	1,043	90,306	8	130,375	0.0866
5	TGS2B-S $	79	7,194	1	79,000	0.0911
6	TGS2-R-N-S	3	1,220			0.4067
7	TOU-GS-3-B-S	1,925	232,897	1	1,925,000	0.1210
8	TPA2-A	210	44,867	11	19,091	0.2137
9	TPA2-A-N	17	3,399	1	17,000	0.1999
10	TPA2-B	708	179,000	97	7,299	0.2528
11	TPA2-B $	1	147			0.1470
12	TPA2-B-API	132	18,361	1	132,000	0.1391
13	TPA2-B-N	11	2,186	1	11,000	0.1987
14						
15	OTHER ADJUSTMENTS		-167			
16						
17	TOTAL ACCOUNT 440	30,093,100	4,965,143,679	4,381,516	6,868	0.1650
18						
19						
20						
21	ACCOUNT 442					
22						
23	AL-2	155,212	12,788,375	8,420	18,434	0.0824
24	AL-2 @	5,184	104,583	70	74,057	0.0202
25	AL-2 $	877	19,707	25	35,080	0.0225
26	AL-2-A		-18			
27	GS-1	121,937	22,110,718	1,191	102,382	0.1813
28	GS-1 @	774	70,553	10	77,400	0.0912
29	GS1-APSE	1,263	217,899	2	631,500	0.1725
30	GS1-APSE @	36	3,137			0.0871
31	GS1-APSE-N	24	457			0.0190
32	GS1-C-APSE		26			
33	GS-1-CARE	29	3,279			0.1131
34	GS-1-G-S		7			
35	GS-1-N	661	74,179	6	110,167	0.1122
36	GS-2	341,138	49,708,922	387	881,494	0.1457
37	GS-2 @	31,705	2,215,828	19	1,668,684	0.0699
38	GS2/1BL-APSE	411	70,237	1	411,000	0.1709
39	GS2/1BL-APSE@	11	1,504			0.1367
40	GS2/1BLAPSE-N	2	371			0.1855
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 442 CONTINUED					
2	GS-2-APS	2	1,541			0.7705
3	GS2-APSE	8,845	1,402,561	10	884,500	0.1586
4	GS2-APSE @	2,940	207,616	1	2,940,000	0.0706
5	GS2-APSE-N	220	35,370			0.1608
6	GS2-APSE-N @	-259	-16,163			0.0624
7	GS2-C-APSE	33	2,974			0.0901
8	GS-2-CARE	331	32,780	1	331,000	0.0990
9	GS-2-CARE-N		-5			
10	GS-2-CPP	4	4,178			1.0445
11	GS-2-N	2,719	358,939	6	453,167	0.1320
12	GS-2-S	361	-12,931			-0.0358
13	GS2T-B-APSE @		-13,717			
14	GS2-TOU-S-B	-137	-12,163			0.0888
15	GS-TOU-EV-3	8	2,028	1	8,000	0.2535
16	GS-TOU-EV-3A	179	32,208	28	6,393	0.1799
17	GSTOU-EV-3A $	8	689	1	8,000	0.0861
18	GS-TOU-EV-3B	12	3,115	3	4,000	0.2596
19	GS-TOU-EV-4	4,360	550,926	34	128,235	0.1264
20	GS-TOU-EV-4@	150	-28,389	2	75,000	-0.1893
21	LS-1-ALLNITE	13,752	4,358,547	2,786	4,936	0.3169
22	LS1-ALLNITE@	139	30,820	8	17,375	0.2217
23	LS1-ALLNITE $			1		
24	LS-1-MIDNITE	8	2,730	1	8,000	0.3413
25	LS1-TAP	122	33,034			0.2708
26	LS-2	2,508	234,518	221	11,348	0.0935
27	LS-2 @	9	402	2	4,500	0.0447
28	LS-2 $	5	175	1	5,000	0.0350
29	LS-2-B	27	3,482	4	6,750	0.1290
30	LS-3	24,135	2,230,448	2,953	8,173	0.0924
31	LS-3 @	1,628	56,824	152	10,711	0.0349
32	LS-3 $	77	2,858	10	7,700	0.0371
33	OL-1-ALLNITE	9,709	2,341,236	6,070	1,600	0.2411
34	OL-1ALLNITE@	106	16,713	43	2,465	0.1577
35	OL-1ALLNITE$	1	138	7	143	0.1380
36	OL-1-MIDNITE		49	1		
37	PA-1	16,710	4,681,000	827	20,206	0.2801
38	PA-1 @	133	16,128	3	44,333	0.1213
39	PA-1-I-API		472			
40	PA-1-N	73	37,369	3	24,333	0.5119
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 442 CONTINUED					
2	PA-1-SPEC-5	1,585	372,067	107	14,813	0.2347
3	PA-2	13,481	2,322,557	155	86,974	0.1723
4	PA-2 @	686	35,986	2	343,000	0.0525
5	PA-2-I-API	94	14,562	1	94,000	0.1549
6	PA-2-N	12	1,243			0.1036
7	T8BAPSECPPN-S	1,466	250,706	2	733,000	0.1710
8	T8-RTP-BIPN-P	2,784	590,278	1	2,784,000	0.2120
9	T8-RTP-BIP-P	46,836	7,946,145	7	6,690,857	0.1697
10	T8-RTP-BIP-S	81,018	11,590,472	19	4,264,105	0.1431
11	T8-RTP-BIP-T	434,377	38,641,100	6	72,396,167	0.0890
12	T8-RTP-DL-S #		37,680			
13	T8-RTP-P	54,055	8,672,857	11	4,914,091	0.1604
14	T8-RTP-S	82,947	14,537,999	43	1,929,000	0.1753
15	T8-RTP-S-P	4,270	506,470	1	4,270,000	0.1186
16	T8-RTP-S-T	501,394	46,128,736	4	125,348,500	0.0920
17	T8-RTP-T	38,268	4,414,378	2	19,134,000	0.1154
18	T8-S-APSE-P	68,676	8,240,176	3	22,892,000	0.1200
19	T8-S-APSE-P @	8,120	472,797	1	8,120,000	0.0582
20	T8-S-APSE-S	3,678	680,807	2	1,839,000	0.1851
21	T8-S-BIP-P	74,861	8,385,813	8	9,357,625	0.1120
22	T8-S-BIP-P @	24,041	843,026	1	24,041,000	0.0351
23	T8-S-BIP-S	25,353	2,737,532	4	6,338,250	0.1080
24	T8-S-BIP-S @	9,724	336,841	1	9,724,000	0.0346
25	T8-S-BIP-T	749,972	59,550,267	5	149,994,400	0.0794
26	T8-S-BIP-T @	230,522	3,734,773	3	76,840,667	0.0162
27	T8-S-P	424,902	55,085,866	59	7,201,729	0.1296
28	T8-S-P @	179,055	9,960,470	13	13,773,462	0.0556
29	T8-S-P $	107	9,370			0.0876
30	T8-S-S	122,443	16,236,678	35	3,498,371	0.1326
31	T8-S-S @	51,375	2,443,837	8	6,421,875	0.0476
32	T8-S-T	550,435	60,165,129	89	6,184,663	0.1093
33	T8-S-T @	222,047	7,818,849	13	17,080,538	0.0352
34	T8-S-T $	63	8,475			0.1345
35	TC-1	51,576	9,624,312	13,371	3,857	0.1866
36	TC-1 @	1,701	174,803	349	4,874	0.1028
37	TC-1 $	245	30,784	83	2,952	0.1256
38	TG2BAPSECPPNS	662	118,779	4	165,500	0.1794
39	TG3BAPSECPPNS	2,551	484,303	7	364,429	0.1898
40	TGS1-A	4,285,325	794,225,211	404,654	10,590	0.1853
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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1	ACCOUNT 442 CONTINUED					
2	TGS1-A @	55,759	4,886,311	4,771	11,687	0.0876
3	TGS1-A $	6,519	669,588	1,098	5,937	0.1027
4	TGS1-A-APSE	77,410	12,969,855	5,300	14,606	0.1675
5	TGS1-A-APSE @	2,391	164,525	167	14,317	0.0688
6	TGS1-A-APSE $	154	13,039	18	8,556	0.0847
7	YGS1-A-APSE-C	32	3,896	1	32,000	0.1218
8	TGS1AAPSE-CPP	9	1,478	1	9,000	0.1642
9	TGS1-A-APSE-N	625	57,907	40	15,625	0.0927
10	TGS1A-APSE-N$	5	67			0.0134
11	TGS1-A-C	1,259	151,273	63	19,984	0.1202
12	TGS1-A-C-N	93	8,532	2	46,500	0.0917
13	TGS1-A-CPP	3,833	712,020	519	7,385	0.1858
14	TGS1-A-CPP-N	32	3,592	1	32,000	0.1123
15	TGS1-A-N	18,335	1,876,879	1,171	15,658	0.1024
16	TGS1-A-N $	78	1,565	4	19,500	0.0201
17	TGS1-B	1,007,749	133,442,465	30,654	32,875	0.1324
18	TGS1-B @	76,647	5,316,608	8,221	9,323	0.0694
19	TGS1-B $	1,344	73,817	57	23,579	0.0549
20	TGS1-B-APSE	22,490	2,996,625	506	44,447	0.1332
21	TGS1-B-APSE @	494	21,177	7	70,571	0.0429
22	TGS1-B-APSE $	73	4,150	1	73,000	0.0568
23	TGS1-B-APSE-C	52	4,341	1	52,000	0.0835
24	TGS1-B-APSE-N	11	726	1	11,000	0.0660
25	TGS1-B-C	520	48,537	12	43,333	0.0933
26	TGS1-B-N	1,478	158,015	43	34,372	0.1069
27	TGS1-B-N $	8	475			0.0594
28	TGS1-B-S	249	39,038	8	31,125	0.1568
29	TGS1-RTP	66	14,223	13	5,077	0.2155
30	TGS2AAPSE-C-S	69	8,760	1	69,000	0.1270
31	TGS2AAPSE-N-S	2,185	397,288	24	91,042	0.1818
32	TGS2AAPSEN-S@	105	22,919	1	105,000	0.2183
33	TGS2A-APSENS$	5	957			0.1914
34	TGS2A-APSE-P	441	79,526	1	441,000	0.1803
35	TGS2A-APSE-S	158,304	33,381,860	1,662	95,249	0.2109
36	TGS2A-APSE-S@	3,606	331,960	23	156,783	0.0921
37	TGS2A-APSE-S$	352	34,633	6	58,667	0.0984
38	TGS2A-C-N-S	50	6,181	1	50,000	0.1236
39	TGS2A-C-S	899	113,956	7	128,429	0.1268
40	TGS2A-N-P	295	44,154	1	295,000	0.1497
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
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1	ACCOUNT 442 CONTINUED					
2	TGS2A-N-S	8,960	1,387,675	77	116,364	0.1549
3	TGS2A-N-S @	43	10,827	1	43,000	0.2518
4	TGS2A-N-S $	12	2,166			0.1805
5	TGS2A-P	3,650	772,911	29	125,862	0.2118
6	TGS2A-S	906,623	195,451,613	11,033	82,174	0.2156
7	TGS2A-S @	15,965	1,518,923	97	164,588	0.0951
8	TGS2A-S $	1,103	172,685	28	39,393	0.1566
9	TGS2A-T	4	7,905	1	4,000	1.9763
10	TGS2BAPSECPPS	6,815	1,208,759	20	340,750	0.1774
11	TGS2BAPSE-C-S	893	108,750	8	111,625	0.1218
12	TGS2BAPSE-N-S	5,602	1,022,930	48	116,708	0.1826
13	TGS2BAPSEN-S@	6,760	456,853	19	355,789	0.0676
14	TGS2B-APSE-P	1,112	180,956	4	278,000	0.1627
15	TGS2B-APSE-S	331,246	58,955,691	2,387	138,771	0.1780
16	TGS2B-APSE-S@	197,220	12,493,644	613	321,729	0.0633
17	TGS2B-APSE-S$	1,184	96,278	10	118,400	0.0813
18	TGS2B-C-N-S	815	84,768	3	271,667	0.1040
19	TGS2B-CPP-N-P	-183	-18,301			0.1000
20	TGS2B-CPP-N-S	7,494	1,008,253	19	394,421	0.1345
21	TGS2B-CPP-P	3,766	607,574	16	235,375	0.1613
22	TGS2B-CPP-S	211,099	32,512,678	453	466,002	0.1540
23	TGS2B-CPP-T	148	17,441	1	148,000	0.1178
24	TGS2B-C-S	9,909	1,127,772	56	176,946	0.1138
25	TGS2B-DL-S #		146,101			
26	TGS2B-EDW	571	94,335	5	114,200	0.1652
27	TGS2B-N-P	255	30,933	1	255,000	0.1213
28	TGS2B-N-S	80,019	12,992,268	527	151,839	0.1624
29	TGS2B-N-S @	907	73,752	4	226,750	0.0813
30	TGS2B-N-S $	21	2,975			0.1417
31	TGS2B-P	41,073	6,338,979	142	289,246	0.1543
32	TGS2B-P @	1,916	128,205	5	383,200	0.0669
33	TGS2B-S	10,658,079	1,769,124,253	68,052	156,617	0.1660
34	TGS2B-S @	1,605,231	112,027,983	5,598	286,751	0.0698
35	TGS2B-S $	14,223	1,285,783	144	98,771	0.0904
36	TGS2BS-APSE-S	-406	92,815	3	-135,333	-0.2286
37	TGS2B-S-P	4,241	840,905	25	169,640	0.1983
38	TGS2B-S-P $	6	807			0.1345
39	TGS2B-S-S	4,992	859,850	15	332,800	0.1722
40	TGS2B-S-T	1,227	221,921	8	153,375	0.1809
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
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1	ACCOUNT 442 CONTINUED					
2	TGS2B-S-T @	218	11,555	1	218,000	0.0530
3	TGS2B-T	2,552	342,221	7	364,571	0.1341
4	TGS2B-T @	252	15,417	1	252,000	0.0612
5	TGS2RAPSE-N-S	10,653	1,402,290	86	123,872	0.1316
6	TGS2RAPSEN-S@	811	80,810	7	115,857	0.0996
7	TGS2RAPSEN-S$	256	23,024	3	85,333	0.0899
8	TGS2-R-APSE-S	52	12,479	1	52,000	0.2400
9	TGS2R-APSE-S@	47	5,494			0.1169
10	TGS2-R-N-P	403	62,931	1	403,000	0.1562
11	TGS2-R-N-S	46,724	5,950,796	331	141,160	0.1274
12	TGS2-R-N-S @	670	75,689	4	167,500	0.1130
13	TGS2-R-N-S $	2,566	251,752	16	160,375	0.0981
14	TGS2-R-S	544	91,783	4	136,000	0.1687
15	TGS2-R-S @	111	13,786	1	111,000	0.1242
16	TGS2-RTP-S	69	15,051	1	69,000	0.2181
17	TGS3-C-CPP-S	2,775	262,168	3	925,000	0.0945
18	TGS3CPP-BIP-S	3,041	331,425	1	3,041,000	0.1090
19	TGS3-CPP-N-P	956	115,330	2	478,000	0.1206
20	TGS3-CPP-N-S	29,319	4,297,028	35	837,686	0.1466
21	TGS3-CPP-P	34,277	5,157,947	35	979,343	0.1505
22	TGS3-CPP-S	1,667,919	264,256,574	1,758	948,759	0.1584
23	TGS3-CPP-T	1,887	250,022	1	1,887,000	0.1325
24	TGS3RAPSE-N-P	3,663	350,615	4	915,750	0.0957
25	TGS3RAPSE-N-S	18,335	2,408,193	38	482,500	0.1313
26	TGS3RAPSEN-S@	1,104	114,499	3	368,000	0.1037
27	TGS3-R-APSE-S	29	4,478			0.1544
28	TGS3-R-APSE-S@	53	6,808			0.1285
29	TGS3-R-BIPN-S	559	22,680	1	559,000	0.0406
30	TGS3-R-CPPN-S	901	147,072	1	901,000	0.1632
31	TGS3-R-N-P	5,446	587,659	7	778,000	0.1079
32	TGS3-R-N-P @	517	53,399	1	517,000	0.1033
33	TGS3-R-N-P $	163	5,911			0.0363
34	TGS3-R-N-S	75,628	10,282,151	140	540,200	0.1360
35	TGS3-R-N-S @	17,138	1,614,024	18	952,111	0.0942
36	TGS3-R-N-S $	1,797	186,655	5	359,400	0.1039
37	TGS3-R-S	197	90,068	1	197,000	0.4572
38	TGS3-R-S @	1,437	137,696	2	718,500	0.0958
39	TGS3RTP-BIP-S	5,180	924,934	7	740,000	0.1786
40	TGS3-RTP-P	1,000	219,843	2	500,000	0.2198
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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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.
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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 442 CONTINUED					
2	TGS3-RTP-S	2,924	618,285	6	487,333	0.2115
3	TOU8-CPP-N-P	19,511	2,677,793	5	3,902,200	0.1372
4	TOU8-CPP-N-S	35,390	4,786,374	10	3,539,000	0.1352
5	TOU8-CPP-P	433,466	59,731,558	110	3,940,600	0.1378
6	TOU8-CPP-S	1,153,177	176,325,607	439	2,626,827	0.1529
7	TOU8-CPP-T	89,819	10,070,406	12	7,484,917	0.1121
8	TOU-8-DL-S #		9,201,837			
9	TOU8-N-P $	1,750	109,095	1	1,750,000	0.0623
10	TOU8-P $	3,308	223,558	1	3,308,000	0.0676
11	TOU8R-BIP-N-S	1,646	133,746	1	1,646,000	0.0813
12	TOU8-R-N-P	68,261	8,724,768	24	2,844,208	0.1278
13	TOU8-R-N-P @	5,230	419,529	2	2,615,000	0.0802
14	TOU8-R-N-P $	2,064	139,618	1	2,064,000	0.0676
15	TOU8-R-N-S	69,274	9,346,789	37	1,872,270	0.1349
16	TOU8-R-N-S @	15,213	1,282,469	9	1,690,333	0.0843
17	TOU8-R-N-S $	580	65,505	1	580,000	0.1129
18	TOU8-R-N-T	1,881	237,605	1	1,881,000	0.1263
19	TOU8-R-P @	23,841	1,516,350	3	7,947,000	0.0636
20	TOU8-R-S	2,014	309,572	1	2,014,000	0.1537
21	TOU8-R-S @	23,832	1,520,639	8	2,979,000	0.0638
22	TOU8-S $	3,440	216,787	1	3,440,000	0.0630
23	TOU-8-S-T		-786,068			
24	TOU8-T $	2,039	76,726			0.0376
25	TOUG3A-APSE-P	1,333	241,320	2	666,500	0.1810
26	TOUG3AAPSE-P@	1,352	99,850	1	1,352,000	0.0739
27	TOUG3A-APSE-S	218,764	43,982,556	469	466,448	0.2011
28	TOUG3AAPSE-S@	17,365	1,821,014	39	445,256	0.1049
29	TOUG3A-APSES$	77	10,839			0.1408
30	TOUG3B-APSE-P	13,257	1,899,236	10	1,325,700	0.1433
31	TOUG3BAPSE-P@	1,829	141,506	1	1,829,000	0.0774
32	TOUG3B-APSE-S	171,097	29,268,891	215	795,800	0.1711
33	TOUG3BAPSE-S@	19,627	1,688,351	25	785,080	0.0860
34	TOU-GS1B-G-S	6	1,410	1	6,000	0.2350
35	TOU-GS3-A-P	5,918	1,157,384	10	591,800	0.1956
36	TOU-GS3-A-P @	1,720	116,185	1	1,720,000	0.0675
37	TOU-GS3-A-P-N	304	64,661			0.2127
38	TOU-GS-3-A-S	446,584	87,116,085	737	605,948	0.1951
39	TOU-GS3-A-S @	34,840	3,434,987	49	711,020	0.0986
40	TOUGS3AS-BIP	12,244	2,305,340	18	680,222	0.1883
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 442 CONTINUED					
2	TOUGS3AS-BIP @	2,755	201,191	3	918,333	0.0730
3	TOU-GS3-A-S-N	17,032	2,670,063	29	587,310	0.1568
4	TOU-GS3B-C-P	1,036	111,961	1	1,036,000	0.1081
5	TOU-GS3B-C-S	5,975	571,202	5	1,195,000	0.0956
6	TOU-GS3B-EDW	597	88,132	1	597,000	0.1476
7	TOU-GS3-B-P	80,454	11,830,245	66	1,219,000	0.1470
8	TOU-GS3-B-P @	16,747	1,215,574	11	1,522,455	0.0726
9	TOUGS3BP-BIP	12,897	1,656,107	9	1,433,000	0.1284
10	TOU-GS3-B-P-N	4,562	630,390	4	1,140,500	0.1382
11	TOUGS3-B-P-N@	1,798	130,636	1	1,798,000	0.0727
12	TOU-GS-3-B-S	3,217,200	466,810,060	2,567	1,253,292	0.1451
13	TOU-GS3-B-S @	2,012,453	132,376,186	1,257	1,600,997	0.0658
14	TOU-GS3-B-S $	3,875	281,485	5	775,000	0.0726
15	TOUGS3BS-BIP	124,233	15,802,557	78	1,592,731	0.1272
16	TOUGS3BS-BIP@	63,326	3,640,361	45	1,407,244	0.0575
17	TOUGS3BS-BIPN	40	8,092			0.2023
18	TOUGS3BS-CPP	-1,641	-339,678			0.2070
19	TOU-GS3-B-S-N	49,777	7,433,155	47	1,059,085	0.1493
20	TOUGS3-B-S-N@	22,160	1,855,346	17	1,303,529	0.0837
21	TOUGS3-B-S-N$	553	44,327	1	553,000	0.0802
22	TOU-GS3B-S-P	2,720	625,112	5	544,000	0.2298
23	TOU-GS3B-S-S	26,412	3,591,595	22	1,200,545	0.1360
24	TOU-GS3B-S-S@	3,185	308,356	3	1,061,667	0.0968
25	TOU-GS3B-S-T	2,241	401,699	10	224,100	0.1792
26	TOU-GS3-B-T	2,488	383,662	4	622,000	0.1542
27	TOU-GS3SOP-S	3,983	786,623	6	663,833	0.1975
28	TOU-PA-B		769			
29	TOU-PA-ICE	37,160	3,497,939	151	246,093	0.0941
30	TOUPA-ICE-API	19,460	1,514,722	83	234,458	0.0778
31	TOU-PA-SOP-2		-3,706			
32	TPA2-A	278,357	45,895,465	4,396	63,321	0.1649
33	TPA2-A @	65	6,737	2	32,500	0.1036
34	TPA2-A $	145	18,318	2	72,500	0.1263
35	TPA2-A-API	18,484	2,572,854	138	133,942	0.1392
36	TPA2-A-API $	14	1,570			0.1121
37	TPA2-A-API-N	1,591	143,201	8	198,875	0.0900
38	TPA2-A-API-N$	11	1,129			0.1026
39	TPA2-A-CPP	458	54,025	2	229,000	0.1180
40	TPA2-A-N	1,890	126,623	18	105,000	0.0670
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 442 CONTINUED					
2	TPA2-B	1,368,862	190,004,669	15,955	85,795	0.1388
3	TPA2-B @	30,074	1,552,381	173	173,838	0.0516
4	TPA2-B $	724	70,425	16	45,250	0.0973
5	TPA2-B-API	172,835	19,543,217	642	269,213	0.1131
6	TPA2-B-API @	1,576	69,600	4	394,000	0.0442
7	TPA2-B-API-N	922	97,330	4	230,500	0.1056
8	TPA2-B-CPP	5,197	569,625	13	399,769	0.1096
9	TPA2-B-DL #		31			
10	TPA2-B-N	5,815	676,260	52	111,827	0.1163
11	TPA2-B-S	750	83,748	4	187,500	0.1117
12	TPA2-RTP	2,642	363,725	15	176,133	0.1377
13	TPA2-SOP1	73,527	9,571,074	495	148,539	0.1302
14	TPA2-SOP1 @	317	28,849	3	105,667	0.0910
15	TPA2-SOP1-API	25,439	2,879,206	117	217,427	0.1132
16	TPA2-SOP1-N	496	34,266	6	82,667	0.0691
17	TPA2-SOP2	23,905	3,147,356	144	166,007	0.1317
18	TPA2-SOP2 @	20	3,091	1	20,000	0.1546
19	TPA2-SOP2-API	12,419	1,314,967	41	302,902	0.1059
20	TPA3-A	146,318	18,810,389	235	622,630	0.1286
21	TPA3-A-API	18,930	2,176,531	27	701,111	0.1150
22	TPA3-A-N	29,001	2,233,469	23	1,260,913	0.0770
23	TPA3-B	826,593	95,619,312	840	984,039	0.1157
24	TPA3-B @	27,407	1,570,867	30	913,567	0.0573
25	TPA3-B $	4,532	237,260	5	906,400	0.0524
26	TPA3-B-API	135,036	13,066,587	111	1,216,541	0.0968
27	TPA3B-API-NEM	214	22,007			0.1028
28	TPA3-B-CPP	48,891	5,341,731	28	1,746,107	0.1093
29	TPA3-B-CPP-N	1,250	81,957	1	1,250,000	0.0656
30	TPA3-B-DL #		20,332			
31	TPA3-B-NEM	9,885	993,751	7	1,412,143	0.1005
32	TPA3-B-NEM $	240	15,753			0.0656
33	TPA3-B-S	-3,843	486,752	4	-960,750	-0.1267
34	TPA3-RTP	8,609	1,075,898	10	860,900	0.1250
35	TPA3-SOP1	49,048	5,673,388	82	598,146	0.1157
36	TPA3-SOP1 @	1,506	118,033	3	502,000	0.0784
37	TPA3-SOP1-API	16,172	1,604,051	22	735,091	0.0992
38	TPA3-SOP2	38,390	4,631,251	68	564,559	0.1206
39	TPA3-SOP2 @	393	43,043	1	393,000	0.1095
40	TPA3-SOP2-API	5,392	540,691	9	599,111	0.1003
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 442 CONTINUED					
2	TPA3-SOP2-N	874	79,963	1	874,000	0.0915
3	TU8A-N-P	323	35,722			0.1106
4	TU8A-N-S	4,748	638,773	3	1,582,667	0.1345
5	TU8A-P	18,158	2,586,526	4	4,539,500	0.1424
6	TU8A-S	3,042	547,246	3	1,014,000	0.1799
7	TU8A-T	18,795	2,302,055	5	3,759,000	0.1225
8	TU8BAPSECPP-P	18,454	3,246,627	7	2,636,286	0.1759
9	TU8BAPSECPP-S	34,054	6,167,584	20	1,702,700	0.1811
10	TU8B-APSE-N-P	1,831	306,277	1	1,831,000	0.1673
11	TU8B-APSE-N-S	6,653	1,093,420	4	1,663,250	0.1643
12	TU8B-APSE-N-T	116,157	11,610,029	1	116,157,000	0.1000
13	TU8B-APSE-P	66,815	10,912,929	27	2,474,630	0.1633
14	TU8B-APSE-P@	40,682	2,506,048	10	4,068,200	0.0616
15	TU8B-APSE-S	151,993	25,458,889	71	2,140,746	0.1675
16	TU8B-APSE-S@	17,509	1,222,833	9	1,945,444	0.0698
17	TU8B-APSE-T	38,500	3,689,588	1	38,500,000	0.0958
18	TU8B-APSE-T@	99,864	2,867,543	1	99,864,000	0.0287
19	TU8B-CPP-P	8	11,578			1.4473
20	TU8B-CPP-S	-2,577	-504,269			0.1957
21	TU8B-P	1,886,592	241,149,584	248	7,607,226	0.1278
22	TU8B-P @	1,411,869	76,237,510	125	11,294,952	0.0540
23	TU8B-P-BIP	684,991	75,748,869	60	11,416,517	0.1106
24	TU8B-P-BIP @	375,958	16,761,216	29	12,964,069	0.0446
25	TU8B-P-BIP-N	17,275	1,938,922	1	17,275,000	0.1122
26	TU8B-P-BIP-N@	13,807	539,408	1	13,807,000	0.0391
27	TU8B-P-N	283,145	35,012,875	21	13,483,095	0.1237
28	TU8B-S	3,584,601	507,849,507	1,040	3,446,732	0.1417
29	TU8B-S @	1,839,947	114,706,208	466	3,948,384	0.0623
30	TU8B-S-BIP	739,992	92,581,516	143	5,174,769	0.1251
31	TU8B-S-BIP @	332,756	16,945,283	65	5,119,323	0.0509
32	TU8B-S-BIP-N	10,149	1,278,387	1	10,149,000	0.1260
33	TU8B-S-BIP-N@	11,708	601,120	1	11,708,000	0.0513
34	TU8B-S-N	181,107	25,362,996	44	4,116,068	0.1400
35	TU8B-S-N @	19,578	1,593,387	9	2,175,333	0.0814
36	TU8B-S-T	112,864	9,256,211			0.0820
37	TU8B-S-T-BIP		-77,783			
38	TU8B-T	1,436,081	133,658,838	32	44,877,531	0.0931
39	TU8B-T @	1,317,420	43,023,176	28	47,050,714	0.0327
40	TU8B-T-BIP	1,254,131	101,074,866	25	50,165,240	0.0806
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

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1	ACCOUNT 442 CONTINUED					
2	TU8B-T-BIP @	783,440	16,402,001	9	87,048,889	0.0209
3	TU8B-T-BIP-N	115,296	10,396,707	2	57,648,000	0.0902
4	TU8B-T-N	164,651	15,691,744	4	41,162,750	0.0953
5	TU8R-APSE-N-P	10,975	1,202,101	7	1,567,857	0.1095
6	TU8RAPSEN-P $	1,913	128,140	1	1,913,000	0.0670
7	TU8R-APSE-N-S	20,706	2,521,922	15	1,380,400	0.1218
8	TU8RAPSE-N-S@	2,965	267,591	2	1,482,500	0.0902
9	TU8RAPSEN-S $	816	53,798	1	816,000	0.0659
10	TUG3AAPSE-N-P	401	58,483			0.1458
11	TUG3AAPSE-N-S	2,387	430,606	7	341,000	0.1804
12	TUG3AAPSEN-S@	64	15,501			0.2422
13	TUG3BAPSECPPP	3,411	618,858	6	568,500	0.1814
14	TUG3BAPSECPPS	26,205	4,876,212	46	569,674	0.1861
15	TUG3BAPSE-N-S	2,106	354,870	3	702,000	0.1685
16	TUG3BAPSEN-S@	968	68,924	1	968,000	0.0712
17	TUG3BAPSE-S-S	988	164,873	1	988,000	0.1669
18	TUGS3-B-S-DL#		75,099			
19	WIRETECHRATE	5,842	1,005,590			0.1721
20						
21	OTHER ADJUSTMENTS		-139,070			
22						
23	TOTAL ACCOUNT 442	55,936,701	7,168,946,717	621,824	89,956	0.1282
24						
25	ACCOUNT 444					
26						
27	AL-2	508	40,229	26	19,538	0.0792
28	GS-1	69	13,083	5	13,800	0.1896
29	GS-1-N	1	26			0.0260
30	GS-2	183	19,464	1	183,000	0.1064
31	LS-1-ALLNITE	334,778	92,200,702	3,798	88,146	0.2754
32	LS1-ALLNITE@	3,041	640,798	12	253,417	0.2107
33	LS1-ALLNITE$	7,325	1,428,580	20	366,250	0.1950
34	LS-2	96,191	10,040,493	3,827	25,135	0.1044
35	LS-2 @	2,424	289,415	66	36,727	0.1194
36	LS-2 $	616	20,688	40	15,400	0.0336
37	LS-2-B	230	35,505	13	17,692	0.1544
38	LS-2-B $		29	1		
39	LS-3	54,379	5,048,927	5,764	9,434	0.0928
40	LS-3 @	6,645	247,408	656	10,130	0.0372
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	ACCOUNT 444 CONTINUED					
2	LS-3 $	136	5,210	19	7,158	0.0383
3	TC-1	7,014	1,311,043	1,827	3,839	0.1869
4	TC-1 @	93	9,225	17	5,471	0.0992
5	TC-1 $	50	6,748	20	2,500	0.1350
6	TGS1-A	1,202	263,300	286	4,203	0.2191
7	TGS1-A @	8	875	1	8,000	0.1094
8	TGS1-A $	13	1,723	3	4,333	0.1325
9	TGS1-A-N	8	1,573	1	8,000	0.1966
10	TGS1-B	311	40,653	18	17,278	0.1307
11	TGS2A-S	122	34,482	4	30,500	0.2826
12	TGS2B-S	914	138,509	4	228,500	0.1515
13	TU8B-P-BIP	28,674	2,914,468	1	28,674,000	0.1016
14						
15	OTHER ADJUSTMENTS		9,895			
16						
17	TOTAL ACCOUNT 444	544,935	114,763,051	16,430	33,167	0.2106
18						
19	ACCOUNT 445					
20						
21	EDWARDS-AFB	159,213	9,595,637	3	53,071,000	0.0603
22	MARCH-AFB	42,857	2,422,947	1	42,857,000	0.0565
23						
24	OTHER ADJUSTMENTS		-26,426			
25						
26	TOTAL ACCOUNT 445	202,070	11,992,158	4	50,517,500	0.0593
27						
28						
29						
30	ACCOUNT 446					
31						
32	GS-1	3	759			0.2530
33	GS-2	46	5,342			0.1161
34	LS-3	3	465	2	1,500	0.1550
35	TC-1	88	14,559	14	6,286	0.1654
36	TGS1-A	434	83,227	56	7,750	0.1918
37	TGS1-B	58	8,072	1	58,000	0.1392
38	TGS2B-CPP-P	194	28,006			0.1444
39	TGS2B-P	4	967			0.2418
40	TGS2B-S	542	74,109	3	180,667	0.1367
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	ACCOUNT 446 CONTINUED					
2	TGS3-CPP-P	14,704	2,363,882	12	1,225,333	0.1608
3	TGS3-CPP-S	2,420	279,813	1	2,420,000	0.1156
4	TOU8-CPP-P	44,415	6,948,856	18	2,467,500	0.1565
5	TOU-GS3-A-P	3,104	529,966	4	776,000	0.1707
6	TOU-GS3-B-P	830	153,581	2	415,000	0.1850
7	TU8B-P	12,114	1,588,366	2	6,057,000	0.1311
8						
9	OTHER ADJUSTMENTS					
10						
11	TOTAL ACCOUNT 446	78,959	12,079,970	115	686,600	0.1530
12						
13						
14	ACCOUNT 448					
15						
16	GS-1-SCE	34	6,641	5	6,800	0.1953
17	GS-2-SCE	118	31,925	1	118,000	0.2706
18	PA-1-SCE	357	65,835	11	32,455	0.1844
19	PA-2-SCE	195	42,853	5	39,000	0.2198
20						
21	OTHER ADJUSTMENTS					
22						
23	TOTAL ACCOUNT 448	704	147,254	22	32,000	0.2092
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
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39						
40						
41	TOTAL Billed	86,856,470	12,273,072,833	5,019,895	17,302	0.1413
42	Total Unbilled Rev.(See Instr. 6)	393,000	67,556,000	0	0	0.1719
43	TOTAL	87,249,470	12,340,628,833	5,019,895	17,381	0.1414

Schedule Page: 304 Line No.: 1 Column: a
This footnote applies to entire schedule:
"@" Symbol represents Direct Access Rate Schedule;
"$" Symbol represents Community Choice Aggregation Rate Schedule (Lancaster Choice Energy).

Schedule Page: 304 Line No.: 12 Column: d
Less than 12 months' data.

Schedule Page: 304 Line No.: 12 Column: e
Less than 12 months' data.

Schedule Page: 304 Line No.: 25 Column: d
Less than 12 months' data.

Schedule Page: 304 Line No.: 25 Column: e
Less than 12 months' data.

Schedule Page: 304 Line No.: 26 Column: b
Data reflected under parent rate schedule or other applicable tariff.

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Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304 Line No.: 26 Column: e
Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304 Line No.: 26 Column: f
Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304 Line No.: 30 Column: d
Less than 12 months' data.

Schedule Page: 304 Line No.: 30 Column: e
Less than 12 months' data.

Schedule Page: 304.1 Line No.: 2 Column: d
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Schedule Page: 304.1 Line No.: 40 Column: d

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Schedule Page: 304.3 Line No.: 31 Column: d
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Schedule Page: 304.3 Line No.: 31 Column: e
Less than 12 months' data.
Schedule Page: 304.3 Line No.: 37 Column: d
Less than 12 months' data.
Schedule Page: 304.3 Line No.: 37 Column: e
Less than 12 months' data.
Schedule Page: 304.3 Line No.: 39 Column: d
Less than 12 months' data.
Schedule Page: 304.3 Line No.: 39 Column: e
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Schedule Page: 304.4 Line No.: 2 Column: d
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Schedule Page: 304.4 Line No.: 2 Column: e
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Schedule Page: 304.4 Line No.: 5 Column: d
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Schedule Page: 304.4 Line No.: 5 Column: e
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Schedule Page: 304.4 Line No.: 14 Column: d
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Schedule Page: 304.4 Line No.: 14 Column: e
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Schedule Page: 304.4 Line No.: 16 Column: d
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Schedule Page: 304.4 Line No.: 20 Column: e
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Schedule Page: 304.4 Line No.: 33 Column: d
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Schedule Page: 304.4 Line No.: 33 Column: e
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Schedule Page: 304.4 Line No.: 40 Column: d
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Schedule Page: 304.4 Line No.: 40 Column: e
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Schedule Page: 304.5 Line No.: 11 Column: e
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Schedule Page: 304.5 Line No.: 14 Column: e
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Schedule Page: 304.5 Line No.: 15 Column: d

Less than 12 months' data.

Schedule Page: 304.5 Line No.: 15 Column: e
Less than 12 months' data.

Schedule Page: 304.5 Line No.: 17 Column: b
Less than 1 MWh.

Schedule Page: 304.5 Line No.: 17 Column: e
Less than 12 months' data.

Schedule Page: 304.5 Line No.: 17 Column: f
Less than 12 months' data.

Schedule Page: 304.5 Line No.: 18 Column: b
Less than 1 MWh.

Schedule Page: 304.5 Line No.: 18 Column: c
Less than 12 months' data.

Schedule Page: 304.5 Line No.: 18 Column: e
Less than 12 months' data.

Schedule Page: 304.5 Line No.: 18 Column: f
Less than 12 months' data.

Schedule Page: 304.5 Line No.: 20 Column: d
Less than 12 months' data.

Schedule Page: 304.5 Line No.: 20 Column: e
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Schedule Page: 304.5 Line No.: 21 Column: d
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Schedule Page: 304.5 Line No.: 21 Column: e
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Schedule Page: 304.5 Line No.: 28 Column: d
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Schedule Page: 304.5 Line No.: 28 Column: e
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Schedule Page: 304.5 Line No.: 30 Column: d
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Schedule Page: 304.5 Line No.: 30 Column: e
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Schedule Page: 304.5 Line No.: 35 Column: d
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Schedule Page: 304.5 Line No.: 35 Column: e
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Schedule Page: 304.5 Line No.: 38 Column: d
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Schedule Page: 304.5 Line No.: 38 Column: e
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Schedule Page: 304.6 Line No.: 6 Column: d
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Schedule Page: 304.6 Line No.: 6 Column: e
Less than 12 months' data.

Schedule Page: 304.6 Line No.: 11 Column: d
Less than 12 months' data.

Schedule Page: 304.6 Line No.: 11 Column: e
Less than 12 months' data.

Schedule Page: 304.6 Line No.: 15 Column: a
Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load

Settlements, rounding and other miscellaneous adjustments.

Schedule Page: 304.6 Line No.: 26 Column: b

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 26 Column: d

Less than 12 months' data.

Schedule Page: 304.6 Line No.: 26 Column: e

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Schedule Page: 304.6 Line No.: 26 Column: f

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Schedule Page: 304.6 Line No.: 30 Column: d

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Schedule Page: 304.6 Line No.: 30 Column: e

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Schedule Page: 304.6 Line No.: 31 Column: d

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Schedule Page: 304.6 Line No.: 31 Column: e

Less than 12 months' data.

Schedule Page: 304.6 Line No.: 32 Column: b

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 32 Column: d

Less than 12 months' data.

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Schedule Page: 304.6 Line No.: 33 Column: d

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Schedule Page: 304.6 Line No.: 33 Column: e

Less than 12 months' data.

Schedule Page: 304.6 Line No.: 34 Column: b

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 34 Column: d

Less than 12 months' data.

Schedule Page: 304.6 Line No.: 34 Column: e

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Schedule Page: 304.6 Line No.: 34 Column: f

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Schedule Page: 304.6 Line No.: 39 Column: d

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Schedule Page: 304.7 Line No.: 7 Column: e

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 9 Column: b

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 9 Column: d

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 9 Column: e

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Schedule Page: 304.7 Line No.: 9 Column: f

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Schedule Page: 304.7 Line No.: 10 Column: d

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Schedule Page: 304.7 Line No.: 10 Column: e

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Schedule Page: 304.7 Line No.: 12 Column: d

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 12 Column: e

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 13 Column: b

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 13 Column: d

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 13 Column: e

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 13 Column: f

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 14 Column: d

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 14 Column: e

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 23 Column: b

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 23 Column: c

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 23 Column: e

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 23 Column: f

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 25 Column: d

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 25 Column: e

Less than 12 months' data.

Schedule Page: 304.7 Line No.: 36 Column: b

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 36 Column: e
Less than 12 months' data.
Schedule Page: 304.7 Line No.: 36 Column: f
Less than 12 months' data.
Schedule Page: 304.7 Line No.: 39 Column: b
Less than 1 MWh.
Schedule Page: 304.7 Line No.: 39 Column: d
Less than 12 months' data.
Schedule Page: 304.7 Line No.: 39 Column: e
Less than 12 months' data.
Schedule Page: 304.7 Line No.: 39 Column: f
Less than 12 months' data.
Schedule Page: 304.8 Line No.: 6 Column: d
Less than 12 months' data.
Schedule Page: 304.8 Line No.: 6 Column: e
Less than 12 months' data.
Schedule Page: 304.8 Line No.: 12 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.8 Line No.: 12 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.8 Line No.: 12 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.8 Line No.: 12 Column: f
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.8 Line No.: 29 Column: d
Less than 12 months' data.
Schedule Page: 304.8 Line No.: 29 Column: e
Less than 12 months' data.
Schedule Page: 304.8 Line No.: 34 Column: d
Less than 12 months' data.
Schedule Page: 304.8 Line No.: 34 Column: e
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Schedule Page: 304.9 Line No.: 10 Column: d
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Schedule Page: 304.9 Line No.: 10 Column: e
Less than 12 months' data.
Schedule Page: 304.9 Line No.: 27 Column: d
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Schedule Page: 304.9 Line No.: 27 Column: e
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Schedule Page: 304.9 Line No.: 33 Column: d
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Schedule Page: 304.9 Line No.: 33 Column: e
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Schedule Page: 304.10 Line No.: 4 Column: d
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Schedule Page: 304.10 Line No.: 4 Column: e
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Schedule Page: 304.10 Line No.: 19 Column: d
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Schedule Page: 304.10 Line No.: 19 Column: e
Less than 12 months' data.

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Schedule Page: 304.10 Line No.: 25 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.10 Line No.: 25 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.10 Line No.: 25 Column: f
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.10 Line No.: 30 Column: d
Less than 12 months' data.
Schedule Page: 304.10 Line No.: 30 Column: e
Less than 12 months' data.
Schedule Page: 304.10 Line No.: 38 Column: d
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Schedule Page: 304.10 Line No.: 38 Column: e
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 9 Column: d
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 9 Column: e
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 27 Column: d
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 27 Column: e
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 28 Column: d
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 28 Column: e
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 33 Column: d
Less than 12 months' data.
Schedule Page: 304.11 Line No.: 33 Column: e
Less than 12 months' data.
Schedule Page: 304.12 Line No.: 8 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.12 Line No.: 8 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.12 Line No.: 8 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.12 Line No.: 8 Column: f
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.12 Line No.: 23 Column: b
Less than 12 months' data.
Schedule Page: 304.12 Line No.: 23 Column: d
Less than 12 months' data.
Schedule Page: 304.12 Line No.: 23 Column: e
Less than 12 months' data.
Schedule Page: 304.12 Line No.: 23 Column: f
Less than 12 months' data.
Schedule Page: 304.12 Line No.: 24 Column: d
Less than 12 months' data.
Schedule Page: 304.12 Line No.: 24 Column: e

Less than 12 months' data.

Schedule Page: 304.12 Line No.: 29 Column: d

Less than 12 months' data.

Schedule Page: 304.12 Line No.: 29 Column: e

Less than 12 months' data.

Schedule Page: 304.12 Line No.: 37 Column: d

Less than 12 months' data.

Schedule Page: 304.12 Line No.: 37 Column: e

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 17 Column: d

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 17 Column: e

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 18 Column: d

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 18 Column: e

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 28 Column: b

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 28 Column: d

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 28 Column: e

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 28 Column: f

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 31 Column: b

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 31 Column: d

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 31 Column: e

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 31 Column: f

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 36 Column: d

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 36 Column: e

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 38 Column: d

Less than 12 months' data.

Schedule Page: 304.13 Line No.: 38 Column: e

Less than 12 months' data.

Schedule Page: 304.14 Line No.: 9 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.14 Line No.: 9 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.14 Line No.: 9 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.14 Line No.: 9 Column: f

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.14 Line No.: 27 Column: d

Less than 12 months' data.

Schedule Page: 304.14 Line No.: 27 Column: e
Less than 12 months' data.
Schedule Page: 304.14 Line No.: 30 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.14 Line No.: 30 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.14 Line No.: 30 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.14 Line No.: 30 Column: f
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.14 Line No.: 32 Column: d
Less than 12 months' data.
Schedule Page: 304.14 Line No.: 32 Column: e
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 3 Column: d
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 3 Column: e
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 19 Column: d
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 19 Column: e
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 20 Column: d
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 20 Column: e
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 36 Column: d
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 36 Column: e
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 37 Column: b
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 37 Column: d
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 37 Column: e
Less than 12 months' data.
Schedule Page: 304.15 Line No.: 37 Column: f
Less than 12 months' data.
Schedule Page: 304.16 Line No.: 10 Column: d
Less than 12 months' data.
Schedule Page: 304.16 Line No.: 10 Column: e
Less than 12 months' data.
Schedule Page: 304.16 Line No.: 12 Column: d
Less than 12 months' data.
Schedule Page: 304.16 Line No.: 12 Column: e
Less than 12 months' data.
Schedule Page: 304.16 Line No.: 18 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.16 Line No.: 18 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.16 Line No.: 18 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.16 Line No.: 18 Column: f

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.16 Line No.: 19 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.16 Line No.: 19 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.16 Line No.: 21 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.

Schedule Page: 304.16 Line No.: 29 Column: d

Less than 12 months' data.

Schedule Page: 304.16 Line No.: 29 Column: e

Less than 12 months' data.

Schedule Page: 304.16 Line No.: 38 Column: b

Less than 1 MWh.

Schedule Page: 304.16 Line No.: 38 Column: e

Less than 12 months' data.

Schedule Page: 304.16 Line No.: 38 Column: f

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 15 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.

Schedule Page: 304.17 Line No.: 24 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.

Schedule Page: 304.17 Line No.: 32 Column: d

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 32 Column: e

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 33 Column: d

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 33 Column: e

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 38 Column: d

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 38 Column: e

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 39 Column: d

Less than 12 months' data.

Schedule Page: 304.17 Line No.: 39 Column: e

Less than 12 months' data.

Schedule Page: 304.18 Line No.: 9 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.

Schedule Page: 304.18 Line No.: 21 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.

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	CA Independent System Operator		1			
2	Arizona Public Service Company	SF	WSPP-2			
3	Avista Utilities	LU	WSPP-2			
4	Bonneville Power Administration	SF	WSPP-2			
5	Calpine Energy Services LP	SF	FERC Vol. 8			
6	Cargill Power Markets, LLC	SF	WSPP-2			
7	EDF Trading North America, LLC	SF	FERC Vol. 8			
8	Eugene Water & Electric Board	SF	WSPP-2			
9	Exelon Generation Company, LLC	SF	FERC Vol. 8			
10	IBERDROLA Renewables, Inc.	SF	FERC Vol. 8			
11	J. Aron & Company	SF	FERC Vol. 8			
12	Macquarie Energy LLC	SF	FERC Vol. 8			
13	Morgan Stanley Capital Group Inc.	SF	FERC Vol. 8			
14	Nevada Power Company	SF	FERC Vol. 8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Noble Americas Energy Solutions LLC	SF	FERC Vol. 8			
2	NorthWestern Energy	SF	FERC Vol. 8			
3	PacifiCorp	SF	FERC Vol. 8			
4	Portland General Electric Company	SF	FERC Vol. 8			
5	Powerex Corp.	SF	FERC Vol. 8			
6	PPL EnergyPlus, LLC	SF	FERC Vol. 8			
7	Public Service Co. of New Mexico	SF	WSPP-2			
8	Puget Sound Energy, Inc.	SF	WSPP-2			
9	Salt River Project Agricultural Imprvmt	SF	WSPP-2			
10	Seattle City Light	SF	WSPP-2			
11	Sempra Generation	SF	FERC Vol. 8			
12	Shell Energy North America (US), L.P.	SF	FERC Vol. 8			
13	Snohomish County Publ Utility Dist #1	SF	WSPP-2			
14	Tacoma Power	SF	WSPP-2			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	The Energy Authority, Inc.	SF	ERC Vol. 8			
2	TRANSALTA ENERGY MARKETING (US)	SF	WSPP-2			
3	Tucson Electric Power Company	LU	WSPP-2			
4	Vitol Inc.	SF	WSPP-2			
5						
6	Rounding					
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,951,884		96,532,220		96,532,220	1
626		13,313		13,313	2
3,450		47,250		47,250	3
127,091		2,113,181		2,113,181	4
1,872		26,375		26,375	5
2,853		44,140		44,140	6
856		21,630		21,630	7
9,830		185,544		185,544	8
920		18,215		18,215	9
2,330		50,192		50,192	10
33		920		920	11
2,408		50,107		50,107	12
118,844		1,929,735		1,929,735	13
					14
0	0	0	0	0	
4,031,926	0	111,197,752	1	111,197,753	
4,031,926	**0**	**111,197,752**	**1**	**111,197,753**	

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.
2,120		71,256		71,256	1
937		15,482		15,482	2
9,950		205,577		205,577	3
103,903		1,694,135		1,694,135	4
94,951		476,917		476,917	5
36,833		332,499		332,499	6
79		395		395	7
43,242		691,238		691,238	8
725		17,122		17,122	9
49,049		857,185		857,185	10
196		5,560		5,560	11
399,077		4,528,049		4,528,049	12
490		12,100		12,100	13
26,765		449,460		449,460	14
0	0	0	0	0	
4,031,926	0	111,197,752	1	111,197,753	
4,031,926	**0**	**111,197,752**	**1**	**111,197,753**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
35,965		717,525		717,525	1
2,612		43,849		43,849	2
2,035		46,580		46,580	3
		1		1	4
					5
			1	1	6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
4,031,926	0	111,197,752	1	111,197,753	
4,031,926	**0**	**111,197,752**	**1**	**111,197,753**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	208,731	367,302
5	(501) Fuel	-1,098	-1,398,778
6	(502) Steam Expenses		-693,211
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		-47,883
10	(506) Miscellaneous Steam Power Expenses	294,534	928,882
11	(507) Rents		-94,081
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	502,167	-937,769
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	66,402	273,833
16	(511) Maintenance of Structures	93,631	58,546
17	(512) Maintenance of Boiler Plant	45	1,428,229
18	(513) Maintenance of Electric Plant		694,411
19	(514) Maintenance of Miscellaneous Steam Plant		261,989
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	160,078	2,717,008
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	662,245	1,779,239
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	17,237,268	58,532,069
25	(518) Fuel	38,293,583	37,970,375
26	(519) Coolants and Water	11,443,298	6,666,796
27	(520) Steam Expenses	6,463,573	6,942,645
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	4,549,188	4,743,341
31	(524) Miscellaneous Nuclear Power Expenses	25,137,814	54,119,820
32	(525) Rents	9,924	1,769,144
33	TOTAL Operation (Enter Total of lines 24 thru 32)	103,134,648	170,744,190
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	3,534,180	6,582,668
36	(529) Maintenance of Structures	1,066,065	1,418,963
37	(530) Maintenance of Reactor Plant Equipment	7,851,371	7,336,570
38	(531) Maintenance of Electric Plant	8,814,193	8,621,151
39	(532) Maintenance of Miscellaneous Nuclear Plant	1,818,297	16,167,090
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	23,084,106	40,126,442
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	126,218,754	210,870,632
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	8,896,138	8,085,629
45	(536) Water for Power	2,695,184	2,973,372
46	(537) Hydraulic Expenses	1,909,725	1,853,857
47	(538) Electric Expenses	2,536,205	2,173,194
48	(539) Miscellaneous Hydraulic Power Generation Expenses	16,914,841	14,287,289
49	(540) Rents	1,121,645	1,073,522
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	34,073,738	30,446,863
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,533,022	1,436,560
54	(542) Maintenance of Structures	877,232	770,812
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,451,447	2,265,493
56	(544) Maintenance of Electric Plant	3,507,937	2,978,076
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,568,633	1,840,311
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,938,271	9,291,252
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	44,012,009	39,738,115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	5,083,287	4,136,561
63	(547) Fuel	137,854,793	230,927,565
64	(548) Generation Expenses	7,058,285	6,833,358
65	(549) Miscellaneous Other Power Generation Expenses	34,965,273	41,160,229
66	(550) Rents	2,438,311	2,121,316
67	TOTAL Operation (Enter Total of lines 62 thru 66)	187,399,949	285,179,029
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,173,646	1,365,281
70	(552) Maintenance of Structures	580,547	831,769
71	(553) Maintenance of Generating and Electric Plant	14,781,399	19,105,833
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,926,115	3,696,188
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	19,461,707	24,999,071
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	206,861,656	310,178,100
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	4,350,075,281	6,766,932,071
77	(556) System Control and Load Dispatching	1,186,049	997,827
78	(557) Other Expenses	40,043,199	39,255,707
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	4,391,304,529	6,807,185,605
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	4,769,059,193	7,369,751,691
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	8,912,303	12,473,795
84			
85	(561.1) Load Dispatch-Reliability	702,757	574,009
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	8,266,023	7,390,740
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	38,175,349	38,495,593
89	(561.5) Reliability, Planning and Standards Development	5,513,298	5,024,136
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	22,897,866	24,288,640
94	(563) Overhead Lines Expenses	6,226,398	5,047,791
95	(564) Underground Lines Expenses	1,185,906	1,008,294
96	(565) Transmission of Electricity by Others	28,897,353	33,190,275
97	(566) Miscellaneous Transmission Expenses	100,941,252	20,122,107
98	(567) Rents	16,112,096	16,230,045
99	TOTAL Operation (Enter Total of lines 83 thru 98)	237,830,601	163,845,425
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,232,258	2,332,430
102	(569) Maintenance of Structures	224,700	297,337
103	(569.1) Maintenance of Computer Hardware	9,075,331	8,225,512
104	(569.2) Maintenance of Computer Software	13,503,877	13,277,673
105	(569.3) Maintenance of Communication Equipment	7,372,629	5,285,731
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	9,034,113	9,551,547
108	(571) Maintenance of Overhead Lines	30,313,222	39,245,868
109	(572) Maintenance of Underground Lines	998,454	250,563
110	(573) Maintenance of Miscellaneous Transmission Plant	1,908,587	1,378,271
111	TOTAL Maintenance (Total of lines 101 thru 110)	74,663,171	79,844,932
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	312,493,772	243,690,357

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	15,399,244	16,116,636
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	15,399,244	16,116,636
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)	15,399,244	16,116,636
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	24,966,667	28,410,487
135	(581) Load Dispatching		
136	(582) Station Expenses	35,242,358	32,778,620
137	(583) Overhead Line Expenses	61,477,489	57,706,403
138	(584) Underground Line Expenses	5,724,663	5,825,902
139	(585) Street Lighting and Signal System Expenses	9,942	32,405
140	(586) Meter Expenses	24,821,505	25,910,468
141	(587) Customer Installations Expenses	18,391,851	19,294,118
142	(588) Miscellaneous Expenses	81,254,358	87,268,584
143	(589) Rents	2,348,708	1,937,265
144	TOTAL Operation (Enter Total of lines 134 thru 143)	254,237,541	259,164,252
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,004,341	2,070,510
147	(591) Maintenance of Structures	215,352	93,495
148	(592) Maintenance of Station Equipment	11,258,798	5,247,166
149	(593) Maintenance of Overhead Lines	146,050,887	127,977,501
150	(594) Maintenance of Underground Lines	55,910,834	72,066,612
151	(595) Maintenance of Line Transformers	6,520,314	5,363,655
152	(596) Maintenance of Street Lighting and Signal Systems	5,942,210	6,721,984
153	(597) Maintenance of Meters	4,335,166	4,479,880
154	(598) Maintenance of Miscellaneous Distribution Plant	11,090,149	11,695,642
155	TOTAL Maintenance (Total of lines 146 thru 154)	243,328,051	235,716,445
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	497,565,592	494,880,697
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	18,581,083	20,437,162
160	(902) Meter Reading Expenses	11,021,032	13,198,860
161	(903) Customer Records and Collection Expenses	107,448,333	101,402,132
162	(904) Uncollectible Accounts	23,894,155	24,116,526
163	(905) Miscellaneous Customer Accounts Expenses	18,219,666	17,873,237
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	179,164,269	177,027,917

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	53,607,401	69,887,213
168	(908) Customer Assistance Expenses	500,213,479	523,995,526
169	(909) Informational and Instructional Expenses	15,175,159	24,890,028
170	(910) Miscellaneous Customer Service and Informational Expenses	80,002	10,324,573
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	569,076,041	629,097,340
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	5,230,475	5,309,589
176	(913) Advertising Expenses	190,312	5,042,277
177	(916) Miscellaneous Sales Expenses	1,452,093	948,285
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	6,872,880	11,300,151
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	388,180,572	497,776,577
182	(921) Office Supplies and Expenses	194,110,998	164,859,354
183	(Less) (922) Administrative Expenses Transferred-Credit	117,633,265	129,629,436
184	(923) Outside Services Employed	97,403,016	65,611,522
185	(924) Property Insurance	13,240,374	15,983,343
186	(925) Injuries and Damages	98,359,983	136,223,963
187	(926) Employee Pensions and Benefits	166,400,467	204,225,272
188	(927) Franchise Requirements	114,123,922	116,006,665
189	(928) Regulatory Commission Expenses	35,110,806	31,625,727
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	8,785,032	
192	(930.2) Miscellaneous General Expenses	18,594,127	21,915,038
193	(931) Rents	23,119,538	23,634,453
194	TOTAL Operation (Enter Total of lines 181 thru 193)	1,039,795,570	1,148,232,478
195	Maintenance		
196	(935) Maintenance of General Plant	19,035,369	16,369,993
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	1,058,830,939	1,164,602,471
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	7,408,461,930	10,106,467,260

Schedule Page: 320 Line No.: 44 Column: b

Account 535 - Included $21,249 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 45 Column: b

Account 536 - Included $324 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 46 Column: b

Account 537 - Included $2,494 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 46 Column: c

Account 537 - Included $207,460 of energy (pumped) storage costs for Eastwood Power Station in 2014.

Schedule Page: 320 Line No.: 47 Column: b

Account 538 - Included $70,714 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 48 Column: b

Account 539 -Included $3,603 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 48 Column: c

Account 539 - Included $1,326,929 of energy (pumped) storage costs for Eastwood Power Station in 2014.

Schedule Page: 320 Line No.: 54 Column: b

Account 542 -Included $20,600 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 55 Column: b

Account 543 -Included $38,529 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 56 Column: b

Account 544 -Included $199,947 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 57 Column: b

Account 545 -Included $128,259 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 57 Column: c

Account 545 - Included $178,124 of energy (pumped) storage costs for Eastwood Power Station in 2014.

Schedule Page: 320 Line No.: 93 Column: b

Account 562 -Included $10,730 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 107 Column: b

Account 570 -Included $(933) of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 136 Column: b

Account 582 -Included $11,246 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Schedule Page: 320 Line No.: 148 Column: b

Account 592 -Included $16,520 of energy (pumped) storage costs for Eastwood Power Station in 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	NON ASSOC:					
2	BUREAU INDIAN AFFAIRS	OS				
3	SIERRA PACIFIC-FRINGE	OS				
4						
5	COOPERATIVES:					
6	VALLEY ELECTRIC	RQ	218			
7						
8	MUNICIPALITIES:					
9	ANAHEIM, CITY OF FRINGE	OS				
10	BANNING, CITY OF FRINGE	OS				
11	LA DEPT OF WTR & PWR FRINGE	OS				
12	RIVERSIDE, CITY OF FRINGE	OS				
13						
14	OTHER PUBLIC AUTHORITIES:					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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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	DEPARTMENT OF ENERGY - HOOVER -	LF	333			
2	LA DEPARTMENT OF WATER & POWER -					
3	US DEPT OF INTERIOR - BUREAU of	OS				
4	METROPOLITAN WATER DISTRICT - Exch	EX	443			
5	MWD 1987 Benefit Energy - Exch Engy	EX	443			
6	PASADENA, CITY OF - EXCH ENGY	EX	317			
7						
8	Brokers / Other:					
9	BGC FINANCIAL, LP	OS				
10	CHOICE POWER, LP	OS				
11	EQUUS ENERGY GROUP, LLC	OS				
12	INTERCONTINENTAL EXCHANGE	OS				
13	JPMORGAN CHASE BANK N.A.	OS				
14	TULLETT PREBON FINANCIAL SERVICES	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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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	GAS:					
2	ANAHAU ENERGY LLC	SF	FERC VOL. 8			
3	CHEVRON NATURAL GAS A DIV. OF	SF	FERC VOL. 8			
4	DES WHOLESALE, LLC	SF	FERC VOL. 8			
5	FREEPOINT COMMODITIES LLC	SF	FERC VOL. 8			
6	INLAND EMPIRE ENERGY CENTER, LLC	SF	FERC VOL. 8			
7	KERN RIVER COGENERATION CO	SF	FERC VOL. 8			
8	OCCIDENTAL ENERGY MARKETING, INC.	SF	FERC VOL. 8			
9	PACIFIC GAS & ELECTRIC COMPANY-PIP	SF	WSPP-2			
10	SOUTHERN CALIFORNIA GAS COMPANY	SF	FERC VOL. 8			
11	SOUTHERN CALIFORNIA GAS	LF	FERC VOL. 8			
12	SOUTHERN CALIFORNIA GAS COMPANY-	SF	FERC VOL. 8			
13	TENASKA MARKETING VENTURES	SF	FERC VOL. 8			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Municipalities:					
2	CITY OF BAKERSFIELD	OS				
3	CITY OF BURBANK WATER AND POWER	SF	WSPP-2			
4	CITY OF GLENDALE	SF	WSPP-2			
5						
6	Non-Associated Utilities:					
7	ARIZONA PUBLIC SERVICE CO	SF	WSPP-2			
8	NEXTERA ENERGY POWER MARKETING,	SF	WSPP-2			
9	PACIFICORP	SF	FERC Vol. 8			
10	PACIFIC GAS & ELECTRIC COMPANY	SF	WSPP-2			
11	PORTLAND GENERAL ELECTRIC	SF	FERC Vol. 8			
12	PUBLIC SERVICE COMPANY OF NEW	SF	WSPP-2			
13	PUGET SOUND ENERGY, INC.	SF	WSPP-2			
14	SAN DIEGO GAS & ELECTRIC COMPANY	SF	WSPP-2			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.

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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	Other Public Authorities:					
2	BONNEVILLE POWER AUTHORITIES	SF	WSPP-2			
3	L.A.D.W.P.	SF	WSPP-2			
4	POWEREX CORP.	SF	FERC Vol. 8			
5	SALT RIVER PROJECT AGRIC. IMPROVMT	SF	WSPP-2			
6						
7	Power Marketers Detail:					
8	CALPINE ENERGY SERVICES LP	SF	FERC Vol. 8			
9	CARGILL POWER MARKETS, LLC	SF	WSPP-2			
10	CITIGROUP ENERGY INC	SF	FERC Vol. 8			
11	CONCORD ENERGY LLC	SF	FERC Vol. 8			
12	CONOCOPHILLIPS COMPANY	SF	FERC Vol. 8			
13	CONSTELLATION ENERGY COMMODITIES	SF	FERC Vol. 8			
14	DYNEGY MOSS LANDING LLC	LU	FERC Vol. 8			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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.

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	EDF TRADING NORTH AMERICA, LLC	SF	FERC Vol. 8			
2	EL PASO ELECTRIC COMPANY	SF	WSPP-2			
3	ELK HILLS POWER LLC	SF	FERC Vol. 8			
4	EUGENE WATER & ELECTRIC BOARD	SF	WSPP-2			
5	HIGH DESERT POWER PROJECT	LU	FERC Vol. 8			
6	IBERDROLA RENEWABLES, INC	SF	FERC Vol. 8			
7	IBERDROLA ENERGY SERVICES, LLC	LU	FERC Vol. 8			
8	J. ARON & COMPANY	SF	FERC Vol. 8			
9	MACQUARIE ENERGY LLC	SF	FERC Vol. 8			
10	MACQUARIE COOK POWER INC	SF	FERC Vol. 8			
11	MORGAN STANLEY CAPITAL GROUP	SF	FERC Vol. 8			
12	NEVADA POWER COMPANY	SF	FERC Vol. 8			
13	PACIFIC SUMMIT ENERGY LLC	SF	FERC Vol. 8			
14	TWIN EAGLE RESOURCES	SF	FERC Vol. 8			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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	GENON ENERGY MANAGEMENT, LLC	SF	FERC Vol. 8			
2	NOBLE AMERICAS ENERGY, LLC	SF	FERC Vol. 8			
3	SEMPRA GENERATION	SF	FERC Vol. 8			
4	SHELL ENERGY NO AMERICA US, L.P.	SF	FERC Vol. 8			
5	TRANSALTA ENERGY MARKETING (US)	SF	WSPP-2			
6	TUCSON ELECTRIC POWER COMPANY	LU	WSPP-2			
7	VITOL INC.	SF	WSPP-2			
8	EXELON GENERATION COMPANY, LLC	SF	FERC Vol. 8			
9	THE ENERGY AUTHORITY, LLC	SF	FERC Vol. 8			
10	GUZMAN ENERGY, LLC	SF	FERC Vol. 8			
11	BROOKFIELD ENERGY MARKETING LP	SF				
12	AVISTA UTILITIES	LU	WSPP-2			
13	BP ENERGY COMPANY	SF	FERC Vol. 8			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tolling Units:					
2	BE CA LLC	LU	FERC Vol. 8			
3	BLYTHE ENERGY LLC	LU	FERC Vol. 8			
4	CPV SENTINEL, LLC	LU	FERC Vol. 8			
5	EL SEGUNDO ENERGY CENTER LLC	LU	FERC Vol. 8			
6	GENON WEST LP	LU	FERC Vol. 8			
7	KERN RIVER COGENERATION COMPANY	LU	FERC Vol. 8			
8	LA PALOMA GENERATING COMPANY LLC	LU	FERC Vol. 8			
9	NRG LONG BEACH GENERATION LLC	LU	FERC Vol. 8			
10	NRG POWER MARKETING LLC	LU	FERC Vol. 8			
11	VARIOUS SUPPLIERS	SF				
12	WALNUT CREEK ENERGY LLC	LU	FERC Vol. 8			
13	WELLHEAD POWER DELANO	LU	FERC Vol. 8			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NON UTILITIES: QUALIFYING FACILITY					
2	67RK 8ME, LLC	OS				
3	ACE COGENERATION COMPANY	OS				
4	ADELANTO SOLAR II, LLC	OS				
5	ADELANTO SOLAR, LLC	OS				
6	ADERA SOLAR, LLC	OS				
7	ADOBE SOLAR LLC	OS				
8	AES TEHACHAPI WIND (85-A)	OS				
9	AES TEHACHAPI WIND (85-B)	OS				
10	AES TEHACHAPI NORTHWIND	OS				
11	AES TEHACHAPI WIND (VG 4)	OS				
12	AES TEHACHAPI WIND (VG 3)	OS				
13	ALTA MESA PWR PURCH CONTRACT	OS				
14	ALTA WIND I, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	ALTA WIND II, LLC	OS				
2	ALTA WIND III, LLC	OS				
3	ALTA WIND IV, LLC	OS				
4	ALTA WIND V, LLC	OS				
5	ALTA WIND VIII, LLC	OS				
6	ALTAGAS POMONA ENERGY INC.	OS				
7	AMERICAN ENERGY, INC. (FULLERTON)	OS				
8	ANNIE POWER, LLC	OS				
9	BECCA SOLAR, LLC	OS				
10	BERRY PETROLEUM COMPANY	OS				
11	BERRY PETROLEUM	OS				
12	BISHOP TUNGSTEN DEVELOPMENT LLC	OS				
13	BNY WESTERN TRUST COMPANY	OS				
14	BOX CAR II POWER PURCHASE	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	CALIFORNIA PV ENERGY LLC	OS				
2	CALIFORNIA PV ENERGY LLC	OS				
3	CALIFORNIA WATER SERVICE COMPANY	OS				
4	CALLEGUAS MUNICIPAL WATER	OS				
5	CALLEGUAS MWD	OS				
6	CALLEGUAS MWD - UNIT 3 (SANTA ROSA)	OS				
7	CALLEGUAS MWD - SPRINGVILLE HYDRO	OS				
8	CAMERON RIDGE LLC IV	OS				
9	CARSON COGENERATION COMPANY	OS				
10	CATALINA SOLAR 2, LLC	OS				
11	CED ATWELL ISLAND WEST, LLC	OS				
12	CED CORCORAN SOLAR 2 LLC	OS				
13	CENTRAL ANTELOPE DRY RANCH B12,	OS				
14	CENTRAL HYDROELECTRIC CORP.	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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 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	CES DHS SOLAR, LLC (DHS SOLAR 1)	OS				
2	CES DHS SOLAR, LLC (DHS SOLAR 2)	OS				
3	CF SBC MASTER TENANT ONE LLC	OS				
4	CF SBC MASTER TENANT ONE LLC	OS				
5	CHEVRON USA	OS				
6	CITIZEN SOLAR B, LLC	OS				
7	CITY OF LONG BEACH	OS				
8	CITY OF SANTA ANA	OS				
9	CITY OF SANTA BARBARA	OS				
10	CO OF LOS ANGELES - PITCHESS HONOR	OS				
11	COLUMBIA THREE LLC	OS				
12	COMMERCE REFUSE TO ENERGY	OS				
13	CORAM ENERGY LLC	OS				
14	CORONA ENERGY PARTNERS LTD	OS				
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CORONAL LOST HILLS, LLC	OS				
2	CORONUS HESPERIA WEST 1 LLC	OS				
3	CORONUS YUCCA VALLEY EAST 1 LLC	OS				
4	CORONUS YUCCA VALLEY EAST 2 LLC	OS				
5	COSO CLEAN POWER	OS				
6	COSO CLEAN POWER, LLC	OS				
7	COSO ENERGY DEVELOPERS	OS				
8	CTV POWER PURCHASE CONTRACT	OS				
9	DANIEL M. BATES	OS				
10	DEEP SPRINGS COLLEGE	OS				
11	DEL RANCH, LTD., (NILAND #2)	OS				
12	DESERT POWER COMPANY	OS				
13	DESERT STATELINE LLC	OS				
14	DESERT SUNLIGHT LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DESERT WATER AGENCY	OS				
2	DESERT WATER AGENCY (SNOW CREEK)	OS				
3	DESERT WIND III PPC TRUST	OS				
4	DESERT WIND I PPC TRUST	OS				
5	DESERT WIND II PWR PURCH TRUST	OS				
6	DG SOLAR LESSEE II, LLC-PICO RIVERA	OS				
7	DG SOLAR LESSEE, LLC	OS				
8	DG SOLAR LESSEE, LLC (WHITE RD C)	OS				
9	DG SOLAR LESSEE, LLC (WHITE RD N)	OS				
10	DIFWIND FARMS LIMITED V	OS				
11	DIFWIND PARTNERS	OS				
12	DILLON WIND LLC	OS				
13	DIVISION 1	OS				
14	DIVISION 2	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DIVISION 3	OS				
2	DREAMER SOLAR LLC	OS				
3	DREW ENERGY, LLC	OS				
4	DUTCH ENERGY	OS				
5	E. F. OXNARD INCORPORATED	OS				
6	ECOS ENERGY, LLC DIAMOND VALLEY	OS				
7	EDOM HILLS PROJECT 1, LLC	OS				
8	EDOM HILLS PROJECT 1, LLC	OS				
9	ELMORE, LTD	OS				
10	ENERGY DEVELOPMENT & CONST. CORP	OS				
11	ENERGY DEVELOPMENT & CONSTR.	OS				
12	EUI MANAGEMENT PH, INC.	OS				
13	EXPRESSWAY SOLAR C2	OS				
14	EXXONMOBIL PRODUCTION COMPANY	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	FPL ENERGY CABAZON WIND, LLC	OS				
2	FSE BLYTHE I, LLC	OS				
3	FTS MASTER TENANT 1 LLC(RODEO	OS				
4	FTS MASTER TENANT 1 LLC(RODEO	OS				
5	FTS MASTER TENANT 1 LLC(ESA)	OS				
6	FTS MASTER TENANT 1 LLC(ESB)	OS				
7	FTS MASTER TENANT 1 LLC(LDFRB)	OS				
8	FTS PROJECT OWNER 1, LLC(SUMMER	OS				
9	GARNET SOLAR POWER GENERATION	OS				
10	GEYSERS POWER COMPANY, LLC	OS				
11	GOLDEN SPRINGS DEV CO., LLC	OS				
12	GOLDEN SPRINGS DEV CO., LLC	OS				
13	GOLDEN SPRINGS DEVELOP CO.,	OS				
14	GOLDEN SPRINGS DEVELOP CO.,	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	GOLETA WATER DISTRICT	OS				
2	GOSHEN PHASE II LLC	OS				
3	HEBER GEOTHERMAL COMPANY	OS				
4	HELEN SOLAR, LLC (WEST)	OS				
5	HELEN SOLAR, LLC (WEST)	OS				
6	HELIOCENTRIC, LLC	OS				
7	HI HEAD HYDRO INCORPORATED	OS				
8	HIGHLANDER SOLAR 1	OS				
9	HIGHLANDER SOLAR 2	OS				
10	HORSESHOE BEND WIND, LLC	OS				
11	HOUWELING NURSERIES OXNARD, INC.	OS				
12	INDUSTRY METROLINK PV1, LLC	OS				
13	INDUSTRY SOLAR POWER GENERATION	OS				
14	INLAND EMPIRE UTILITIES AGENCY	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	ISABELLA FISH FLOW HYDROELECTRIC	OS				
2	JRAM SOLAR 1 LLC	OS				
3	JRAM SOLAR 2 LLC	OS				
4	JRAM SOLAR 3 LLC	OS				
5	KAWEAH RIVER POWER AUTHORITY	OS				
6	KERN RIVER COGENERATION COMPANY	LU	FERC Vol. 8			
7	KETTERING 1	OS				
8	KETTERING 2	OS				
9	KONA SOLAR LLC-PARK MERIDIAN 1	OS				
10	KONA SOLAR LLC-RANCHO CUCAMONGA	OS				
11	KONA SOLAR LLC-TERRA FRANCESCO 1	OS				
12	L A CO SANITATION DIST	OS				
13	L A CO SANITATION DIST SPADRA	OS				
14	L A CO SANITATION DIST CSD2610	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	L-8 SOLAR PROJECT, LLC	OS				
2	L A CO FLOOD CONTROL DISTRICT	OS				
3	LANCASTER DEL SUR RANCH C2, LLC	OS				
4	LANCASTER LITTLE ROCK C LLC	OS				
5	LEATHERS L. P.	OS				
6	LITTLE ROCK-PHAM SOLAR, LLC	OS				
7	LOMA LINDA UNIVERSITY	OS				
8	LONE VALLEY SOLAR PARK I LLC	OS				
9	LONE VALLEY SOLAR PARK II LLC	OS				
10	LUZ SOLAR PARTNERS LTD III	OS				
11	LUZ SOLAR PARTNERS LTD IV	OS				
12	LUZ SOLAR PARTNERS LTD IX	OS				
13	LUZ SOLAR PARTNERS LTD V	OS				
14	LUZ SOLAR PARTNERS LTD VI	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	LUZ SOLAR PARTNERS LTD VII	OS				
2	LUZ SOLAR PARTNERS LTD VIII	OS				
3	MADELYN SOLAR	OS				
4	MAMMOTH PACIFIC L P II (MP2)	OS				
5	MARINO VENTURES LLC	OS				
6	MCCOY SOLAR, LLC	OS				
7	MITCHELL SOLAR	OS				
8	MM TAJIGUAS ENERGY LLC	OS				
9	MOGUL WIND	OS				
10	MONTE VISTA WATER DIST	OS				
11	MONTECITO WATER DIST	OS				
12	MORGAN LANCASTER, LLC	OS				
13	MOUNTAINVIEW POWER PARTNERS IV,	OS				
14	MOUNTAINVIEW POWER PARTNERS, LLC	OS				
	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:

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MUSTANG HILLS, LLC	OS				
2	NAVAJO SOLAR POWER GENERATION	OS				
3	NAWP INC. (EAST WINDS PROJ)	OS				
4	NEWBERRY SOLAR 1 LLC	OS				
5	NEW-INDY OXNARD, LLC	OS				
6	NORTH HURLBURT WIND, LLC	OS				
7	NORTH PALM SPRINGS #1A	OS				
8	NORTH PALMS SPRINGS INVESTMENTS	OS				
9	NRG SOLAR OASIS LLC	OS				
10	OLS ENERGY - CAMARILLO	OS				
11	OLS ENERGY - CHINO	OS				
12	OAK CREEK ENERGY SYSTEMS INC.	OS				
13	ONE MIRACLE PROPERTY LLC	OS				
14	ORANGE COUNTY SANITATION DISTRICT	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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:

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	ORION SOLAR SOLAR II	OS				
2	ORMESA GEOTHERMAL 1	OS				
3	ORNI 18, LLC	OS				
4	OTOE SOLAR POWER GENERATION STAT	OS				
5	PAINTED HILLS WIND DEVELOPERS	OS				
6	PATTERSON PASS WIND FARM, LLC	OS				
7	PINYON PINES WIND 1, LLC	OS				
8	PINYON PINES WIND II, LLC	OS				
9	PLACER SOLAR, LLC	OS				
10	POWHATAN SOLAR POWER GENERATION	OS				
11	PROCTER & GAMBLE PAPER PROD	OS				
12	PSOMASFMG LANCASTER SOLAR CREDT	OS				
13	PSOMASFMG LANCASTER SOLAR CREDT	OS				
14	PUMPJACK SOLAR I, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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:

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RADIANCE SOLAR 4 LLC	OS				
2	RADIANCE SOLAR 5 LLC	OS				
3	RE ADAMS EAST	OS				
4	RE GARLAND A, LLC	OS				
5	RE ROSEMOND TWO LLC	OS				
6	RE VICTOR PHELAN SOLAR ONE LLC	OS				
7	RHODIA INC.	OS				
8	RICHARD MOSS	OS				
9	RIDGETOP ENERGY, LLC (I)	OS				
10	RIDGETOP ENERGY, LLC (II)	OS				
11	RIO BRAVO JASMIN	OS				
12	RIO GRANDE LLC	OS				
13	RIVERSIDE COUNTY WASTE MGMT	OS				
14	ROYAL FARMS	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	ROYAL FARMS #2	OS				
2	RUDY SOLAR	OS				
3	SALTON SEA POWER Generation #1	OS				
4	SALTON SEA POWER Generation #2	OS				
5	SALTON SEA POWER Generation #3	OS				
6	SALTON SEA POWER Generation #4	OS				
7	SAN BERNARDINO MWD	OS				
8	SAN BERNARDINO MWD 3 4100	OS				
9	SAN GORGONIO WESTWINDS II,	OS				
10	SAN GORGONIO WESTWINDS II, LLC	OS				
11	SANDRA ENERGY LLC	OS				
12	SEARLES VALLEY MINERALS OPERATION	OS				
13	SEARLES VALLEY MINERALS, INC.	OS				
14	SECOND IMPERIAL GEOTHERMAL CO.	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SEC 16-29 TRUST - (ALTECH III)	OS				
2	SECTION 20 TRUST	OS				
3	SECTION 22 TRUST (SAN JACINTO)	OS				
4	SEPV1	OS				
5	SEPV II	OS				
6	SEPV PALMDALE EAST, LLC	OS				
7	SEQUOIA PV 1 LLC (FARMERSVILLE 1)	OS				
8	SEQUOIA PV 1 LLC (FARMERSVILLE 2)	OS				
9	SEQUOIA PV 1 LLC (FARMERSVILLE 3)	OS				
10	SEQUOIA PV 1 LLC (TULARE 1)	OS				
11	SEQUOIA PV 1 LLC (TULARE 2)	OS				
12	SEQUOIA PV 1 LLC (HANFORD 1)	OS				
13	SEQUOIA PV 1 LLC (HANFORD 2)	OS				
14	SEQUOIA PV 1 LLC (PORTERVILLE 6)	OS				
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SEQUOIA PV 1 LLC (PORTERVILLE 7)	OS				
2	SIERRA SOLAR GREENWORKS, LLC	OS				
3	SIERRA SUNTOWER	OS				
4	SIERRA SUNTOWER	OS				
5	SILVER STATE SOLAR POWER SOUTH,	OS				
6	SKY RIVER PTNRSHP - (WILDERNESS I)	OS				
7	SKY RIVER PTNRSHP - (WILDERNESS II)	OS				
8	SKY RIVER PTNRSHP - (WILDERNESS III)	OS				
9	SOLAR PARTNERS I, LLC	OS				
10	SOLAR STAR CALIFORNIA XIII, LLC	OS				
11	SOLAR STAR XIX, LLC	OS				
12	SOLAR STAR XX, LLC	OS				
13	SOUTH HURLBURT WIND, LLC	OS				
14	SP INDIGO RANCH A2, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SP INDIGO RANCH B2, LLC	OS				
2	SP INDIGO RANCH C2, LLC	OS				
3	SS SAN ANTONIO WEST LLC	OS				
4	SUMMER SOLAR A2 LLC	OS				
5	SUMMER SOLAR B2 LLC	OS				
6	SUMMER SOLAR C2 LLC	OS				
7	SUMMER SOLAR D2 LLC	OS				
8	SUN EDISON	OS				
9	SUNE CREST 1 LLC	OS				
10	SUNE CREST 2 LLC	OS				
11	SUNE CREST 3 LLC	OS				
12	SUNE CREST 4 LLC	OS				
13	SUNE CREST 7	OS				
14	SUNE CREST 8 LLC	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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	SUNE W12DG-C, LLC	OS				
2	SUNEDISON UTILITY SOLUTIONS LLC	OS				
3	SUNEDISON UTILITY SOLUTIONS LLC	OS				
4	SUNEDISON UTILITY SOLUTIONS LLC	OS				
5	SUNRAY ENERGY, INC.	OS				
6	SYCAMORE	OS				
7	SYCAMORE COGENERATION COMPANY	OS				
8	TA-HIGH DESERT, LLC	OS				
9	TEHACHAPI POWER PURCHASE	OS				
10	TEMESCAL CANYON (CREST)	OS				
11	TERMO COMPANY	OS				
12	TERRA-GEN 251 WIND, LLC (MONOLITH X)	OS				
13	TERRA-GEN 251 WIND, LLC (MONOLITH	OS				
14	TERRA-GEN 251 WIND, LLC (MONOLITH	OS				
	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	TERRA-GEN 251 WIND, LLC(MONOLITH	OS				
2	TERRA-GEN DIXIE VALLEY, LLC	OS				
3	THREE VALLEYS MWD (FULTON ROAD)	OS				
4	THREE VALLEYS MWD (MIRAMAR)	OS				
5	THREE VALLEYS MWD (WILLIAMS)	OS				
6	TIN INC. DBA TEMPLE-INLAND	OS				
7	TORO POWER 1, LLC	OS				
8	TORO POWER 2, LLC	OS				
9	TREEN SOLAR 2, LLC	OS				
10	TREEN SOLAR 1, LLC	OS				
11	TULARE PV I , LLC (EXETER 1)	OS				
12	TULARE PV I , LLC (EXETER 2)	OS				
13	TULARE PV I , LLC (EXETER 3)	OS				
14	TULARE PV I , LLC (IVANHOE 1)	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	TULARE PV I , LLC (IVANHOE 2)	OS				
2	TULARE PV I , LLC (IVANHOE 3)	OS				
3	TULARE PV I , LLC (LINDSAY 1)	OS				
4	TULARE PV I , LLC (LINDSAY 3)	OS				
5	TULARE PV I , LLC (LINDSAY 4)	OS				
6	TULARE PV I , LLC (POTERVILLE 1)	OS				
7	TULARE PV I , LLC (POTERVILLE 2)	OS				
8	TULARE PV I , LLC (POTERVILLE 5)	OS				
9	U S BORAX	OS				
10	U S BORAX INC.	OS				
11	USDA FOREST SERVICE SAN DIMAS	OS				
12	VARIOUS SMALL PARALLEL	OS				
13	VEGA SOLAR, LLC	OS				
14	VENABLE SOLAR, LLC (NORTH)	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	VENABLE SOLAR, LLC (SOUTH)	OS				
2	VENTURA REGIONAL SANITATION DIST	OS				
3	VICTOR DRY FARM RANCH A, LLC	OS				
4	VICTOR DRY FARM RANCH B, LLC	OS				
5	VICTOR MESA LINDA A, LLC	OS				
6	VICTOR MESA LINDA B2 LLC	OS				
7	VICTOR MESA LINDA C2 LLC	OS				
8	VICTOR MESA LINDA D2 LLC	OS				
9	VICTOR MESA LINDA E2 LLC	OS				
10	VICTORY GARDEN/PHASE IV PARTNER	OS				
11	VICTORY GARDEN/PHASE IV PARTNER	OS				
12	VICTORY GARDEN/PHASE IV PARTNER	OS				
13	VOYAGER SOLAR 1 LLC	OS				
14	VOYAGER SOLAR 2 LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	VOYAGER SOLAR 3 LLC	OS				
2	VULCAN/BN GEOTHERMAL	OS				
3	WATSON COGENERATION COMPANY	OS				
4	WATSON COGENERATION COMPANY	OS				
5	WESTWIND TRUST	OS				
6	WHEELABRATOR NORWALK ENERGY CO	OS				
7	WHITE MOUNTAIN RANCH LLC	OS				
8	WILDWOOD SOLAR I, LLC	OS				
9	WINDLAND REFRESH 1, LLC	OS				
10	WINDLAND REFRESH 2, LLC	OS				
11	WINDRIDGE INCORPORATED	OS				
12	WINDSONG WIND PARK	OS				
13	WINDSTAR ENERGY LLC	OS				
14	WM ENERGY SOL. INC. (EL SOBRANTE)	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	WM ENERGY SOL. INC. (SIMI VALLEY)	OS				
2	ZUNI SOLAR, LLC (NORTH)	OS				
3	ZUNI SOLAR, LLC (SOUTH)	OS				
4	CALIFORNIA ISO - NET					
5	INDEPENDENT EVALUATOR COSTS					
6	VARIOUS ENERGY SETTLEMENT REFUND					
7	LEASE CONVERSION					
8	WECC STATUTORY COSTS					
9	HEDGING - CONGESTION REVENUE					
10	HEDGING - REALIZED					
11	HEDGING - UNREALIZED					
12	REC INVENTORY					
13	REMAT/BIOMAT APPLICATION FEES					
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	GREEN ATTRIBUTES:					
2	CALIFORNIA AIR RESOURCE BOARD					
3	WECC WREGIS CERTIFICATE					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
1,057				96,659		96,659	2
163				15,511		15,511	3
							4
							5
					9,900	9,900	6
							7
							8
20				-167,418		-167,418	9
129				17,462		17,462	10
-310				-30,966		-30,966	11
591				41,943		41,943	12
							13
							14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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)	
-459,695			4,387,264	-16,298,646		-11,911,382	1
-1,500				-262,000		-262,000	2
					135,835	135,835	3
	97,831	19,986		2,871,255		2,871,255	4
		312,537					5
		269					6
							7
							8
					16,323	16,323	9
					27,503	27,503	10
					15,293	15,293	11
					80,267	80,267	12
					2,434,456	2,434,456	13
					13,091	13,091	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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
1,020,393				32,781,499	-312,534	32,468,965	2
					-1,505,179	-1,505,179	3
123,082				4,092,047		4,092,047	4
					-33,275	-33,275	5
					11,837,444	11,837,444	6
					37,609	37,609	7
					-852,549	-852,549	8
					-329,807	-329,807	9
					2,647,700	2,647,700	10
					-126,680	-126,680	11
					-6,552,907	-6,552,907	12
3,200				120,500		120,500	13
							14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
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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.
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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
				-34,897		-34,897	2
25,629				708,358		708,358	3
800				19,200		19,200	4
							5
							6
109,275				2,564,800		2,564,800	7
					18,000	18,000	8
64,609				1,489,340		1,489,340	9
					12,000	12,000	10
160,423				4,986,207		4,986,207	11
18,600				398,350		398,350	12
200				6,000		6,000	13
1,000				28,200		28,200	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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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
1,070,870				35,859,320		35,859,320	2
320				21,840		21,840	3
686,931				23,581,721		23,581,721	4
96,339				2,420,816		2,420,816	5
							6
							7
4,805,941			77,141,836	131,735,970	18,198,173	227,075,979	8
93,812				3,019,610		3,019,610	9
199,449				5,671,729		5,671,729	10
					-36,450	-36,450	11
400				12,900	-3,396,367	-3,383,467	12
-200				-4,750		-4,750	13
535,517			14,152,812	21,403,324	24,038,035	59,594,171	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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.
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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.
340,976				9,708,111	-2,914,313	6,793,798	1
7,800				166,550		166,550	2
25					1,713,500	1,713,500	3
30,541				809,396		809,396	4
					1,832,495	1,832,495	5
277,336				7,485,272	118,028	7,603,300	6
					-1,843,229	-1,843,229	7
387,104				11,890,401	-276,737	11,613,664	8
78,075				1,786,975		1,786,975	9
16,799				326,498	-3,511,760	-3,185,262	10
1,074,510				32,271,454	5,940,000	38,211,454	11
10,302				318,061		318,061	12
					-2,649,729	-2,649,729	13
29,160				678,059		678,059	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.

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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.
703					18,784,274	18,784,274	1
					-1,443,409	-1,443,409	2
148,060				4,357,500	11,215,210	15,572,710	3
133,922				4,390,681	-4,653,644	-262,963	4
80,887				1,872,573		1,872,573	5
2,000				50,600		50,600	6
174,937				6,400,115		6,400,115	7
51,100				1,617,788	-66,300	1,551,488	8
1,712				39,910		39,910	9
54,000				1,789,400		1,789,400	10
400				10,000		10,000	11
200				4,300		4,300	12
					-139,729	-139,729	13
							14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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	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
2,246,889			191,838,486	96,572,284	4,275,539	292,686,309	2
1,312,632			52,745,258	39,744,043	1,897,580	94,386,881	3
646,310			141,706,989	23,657,567	377,727	165,742,283	4
1,950,221			103,746,006	-37,799	2,467,778	106,175,985	5
-328			95,459	24,225	-23,677	96,007	6
				-14,884		-14,884	7
					1,401,600	1,401,600	8
13,149			33,758,319	836,536	-77,494	34,517,361	9
-2,054,843			-14,478,133	37,801	5,128,222	-9,312,110	10
					33,959,178	33,959,178	11
469,973			95,771,112	20,143,914	520,926	116,435,952	12
16,399			7,946,319	443,891	-22,268	8,367,942	13
							14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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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.
							1
11,859				365,905	-200,400	165,505	2
				-1,405,729	5,115,254	3,709,525	3
10,232				662,800		662,800	4
18,699				1,316,645		1,316,645	5
239				17,106		17,106	6
51,063				6,542,520		6,542,520	7
13,063			205,317	405,983		611,300	8
16,355			332,598	506,305		838,903	9
6,203			99,380	193,390		292,770	10
7,558			116,073	242,451		358,524	11
11			23	539		562	12
27,655			971,323	815,027		1,786,350	13
326,422				38,112,797	1,200,000	39,312,797	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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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)	
267,916				31,195,941		31,195,941	1
285,317				33,183,156		33,183,156	2
127,537				15,057,517		15,057,517	3
208,267				24,691,723		24,691,723	4
218,905				26,719,012		26,719,012	5
112,495			6,647,577	4,437,320		11,084,897	6
190			3,780	6,195	-3,488	6,487	7
4,420				624,373		624,373	8
4,409				622,122		622,122	9
280,400			3,066,095	8,419,901	249,768	11,735,764	10
149,184			1,531,637	4,537,926	-21,274	6,048,289	11
605				64,267		64,267	12
2,531			63,664	139,945		203,609	13
14,996			364,920	468,195		833,115	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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.
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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)	
2,046				318,876		318,876	1
3,294				515,134		515,134	2
3,937				346,165		346,165	3
2,066				225,857		225,857	4
101				15,046		15,046	5
243			11,472	7,753		19,225	6
668			6,501	20,071		26,572	7
30,604			668,841	942,218		1,611,059	8
32,864			9,283,704	1,199,479	-4,480	10,478,703	9
25,137				1,684,095	-97,964	1,586,131	10
27,734				1,656,454		1,656,454	11
29,275				3,801,226		3,801,226	12
					-46,200	-46,200	13
			112	-15,712		-15,600	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.

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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)	
2,441				295,077		295,077	1
3,551				432,322		432,322	2
3,177				414,804	-116	414,688	3
3,281				433,455	-116	433,339	4
174,847			983,883	5,650,765		6,634,648	5
409				32,401		32,401	6
202,955			4,380,943	18,145,555		22,526,498	7
8			86	235		321	8
103				8,856		8,856	9
175,958			3,860,555	5,483,487		9,344,042	10
25,664				3,257,156		3,257,156	11
77,733			1,920,210	7,012,087		8,932,297	12
8,100			112,970	245,687		358,657	13
125,802			6,717,655	4,876,197		11,593,852	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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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.
36,930				3,096,493	-336,000	2,760,493	1
					-32,130	-32,130	2
					-3,000	-3,000	3
					-3,000	-3,000	4
437,262			-8	35,536,297		35,536,289	5
480,115			-1	41,087,726		41,087,725	6
298,758			10,574,167	9,401,375		19,975,542	7
22,216			490,510	674,683		1,165,193	8
31			767	21		788	9
4			4	136		140	10
320,109			8,146,772	9,881,487		18,028,259	11
929			4,509	66,435		70,944	12
842				46,499		46,499	13
618,460				90,742,882		90,742,882	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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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)	
				-8,834		-8,834	1
378			4,996	11,178		16,174	2
44,078			1,246,001	1,332,010		2,578,011	3
47,405			1,231,187	1,425,532		2,656,719	4
167,701			3,945,709	4,948,568		8,894,277	5
211				28,342		28,342	6
3,306				449,608		449,608	7
3,991				509,095	-4,620	504,475	8
3,936				503,966	-4,620	499,346	9
10,754			294,384	327,686		622,070	10
17,847			489,111	543,631		1,032,742	11
120,781				8,177,499	-12,594	8,164,905	12
2,951				380,868	-96	380,772	13
2,076				267,118	-183	266,935	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,932				242,130	-615	241,515	1
4,413				621,031		621,031	2
2,967				415,936		415,936	3
18,050			558,501	549,121		1,107,622	4
163,209			10,237,875	6,190,198		16,428,073	5
2,274				305,174		305,174	6
36,417			314,141	1,145,965		1,460,106	7
5,772			8,263	165,869	-10,000	164,132	8
341,378			8,234,435	10,412,020		18,646,455	9
18,567			127,518	567,583		695,101	10
8,703			75,229	269,484	-20,000	324,713	11
38,897			1,067,528	1,180,659		2,248,187	12
3,915				494,068		494,068	13
7,334			46,428	220,372		266,800	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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-1,741			-5,000	-77,710		-82,710	1
45,071				5,219,900		5,219,900	2
3,836				492,813		492,813	3
3,873				495,701		495,701	4
4,839				341,929		341,929	5
4,293				301,739		301,739	6
14,020				1,111,045		1,111,045	7
14,926			216,707	532,079	-28,548	720,238	8
9,377				861,337	-23,400	837,937	9
1,839,114				91,257,275		91,257,275	10
1,851				450,772		450,772	11
1,943				479,828		479,828	12
2,398				408,196		408,196	13
2,772				470,712		470,712	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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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)	
64				4,753		4,753	1
308,238				29,259,082		29,259,082	2
304,837			6,411,222	9,374,903		15,786,125	3
					-39,410	-39,410	4
					-39,410	-39,410	5
2,888				406,314		406,314	6
1,137			8,277	68,239		76,516	7
33,677				2,845,051		2,845,051	8
25,142				2,113,239		2,113,239	9
565,410				57,896,428	5,159,031	63,055,459	10
59,965				3,562,668	-57,830	3,504,838	11
3,167				777,441		777,441	12
4,197				597,008		597,008	13
1,412			8,320	46,206		54,526	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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.
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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)	
2,070				199,915		199,915	1
4,392				615,679		615,679	2
4,409				616,112		616,112	3
2,986				417,178		417,178	4
5,121			339,774	161,149		500,923	5
				103		103	6
2,112				268,532	-48	268,484	7
2,088				267,889	-178	267,711	8
2,583				311,580		311,580	9
2,602				309,450		309,450	10
2,525				304,604		304,604	11
327,360			8,563,331	10,162,763		18,726,094	12
21,075			886,275	688,693		1,574,968	13
			35	-10,651		-10,616	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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.

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,051				421,768		421,768	1
204			52,267	3,065		55,332	2
					-46,200	-46,200	3
13,518				759,495		759,495	4
335,342			7,853,254	10,226,473		18,079,727	5
260				22,937		22,937	6
1,673			1,686	49,482		51,168	7
25,025				1,619,218		1,619,218	8
53,090				3,405,783		3,405,783	9
58,782			4,656,633	2,116,483		6,773,116	10
59,264			4,661,896	2,132,033		6,793,929	11
162,220			16,114,900	5,854,059		21,968,959	12
58,607			4,936,250	2,102,989		7,039,239	13
54,516			5,202,766	1,967,066		7,169,832	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
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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.
47,431			5,020,396	1,742,620		6,763,016	1
156,530			14,895,154	5,619,390		20,514,544	2
2,790				349,309		349,309	3
58,223			1,083,363	1,769,172		2,852,535	4
691				85,294		85,294	5
78,931				2,170,927		2,170,927	6
4,346				545,276		545,276	7
24,117				1,972,149	-200	1,971,949	8
1,551			9,755	38,943	-30,000	18,698	9
55				5,084		5,084	10
62			1,974	1,081		3,055	11
675				62,392		62,392	12
153,055				18,146,137		18,146,137	13
191,931				19,644,639		19,644,639	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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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)	
241,253				29,147,574		29,147,574	1
4,077				573,460		573,460	2
4,557			26,786	135,312		162,098	3
2,582				359,109		359,109	4
91,887			2,028,466	2,954,220		4,982,686	5
482,811				48,688,742	4,737,299	53,426,041	6
5,130				843,382		843,382	7
5,358				814,127		814,127	8
					-228,000	-228,000	9
147,648			4,883,342	5,057,806		9,941,148	10
210,119			4,815,131	7,172,189		11,987,320	11
47,630			1,319,580	1,482,970		2,802,550	12
1,489				197,074		197,074	13
674			1,006	23,118		24,124	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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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.
20,464				1,503,457	-340	1,503,117	1
319,347			7,187,962	9,625,669	-520,800	16,292,831	2
95,657				6,758,186	-4,439	6,753,747	3
3,551				510,300		510,300	4
30,038			487,126	915,143	3,488	1,405,757	5
					-1,188,000	-1,188,000	6
275,132				34,507,651		34,507,651	7
193,488				24,365,930		24,365,930	8
					-1,200,000	-1,200,000	9
4,167				599,184		599,184	10
372,838			11,353,790	11,902,285		23,256,075	11
3,449				441,336		441,336	12
3,513				449,050		449,050	13
52,180			-59,243	3,257,936		3,198,693	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,421				492,882		492,882	1
3,396				491,691		491,691	2
50,668				4,294,704		4,294,704	3
					-450,000	-450,000	4
48,891				7,776,349		7,776,349	5
47,343				7,749,662		7,749,662	6
				22,071		22,071	7
16			403	-185		218	8
15,395			12,648	442,671		455,319	9
71,475			1,938,868	2,205,269		4,144,137	10
			-205,524	42,517	8,257	-154,750	11
11,300				1,736,439		1,736,439	12
6,029				606,351		606,351	13
-8			-10	-383		-393	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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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	-1	1
4,413				553,092		553,092	2
76,027			2,421,911	7,473,969		9,895,880	3
114,134			3,134,823	3,518,781		6,653,604	4
358,935			8,935,760	11,051,971		19,987,731	5
310,010			7,880,789	20,955,207		28,835,996	6
138			1,694	4,473		6,167	7
5				490		490	8
561				27,380		27,380	9
22,347			578,167	682,293		1,260,460	10
4,209				586,945		586,945	11
					-2,500	-2,500	12
19,820			88,505	571,400	-76,972	582,933	13
202,864			6,149,428	6,091,513		12,240,941	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	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.
52,886			1,362,910	1,602,911		2,965,821	1
-412			-2,999	-21,201		-24,200	2
30,295			755,808	923,979		1,679,787	3
5,356				885,840		885,840	4
3,897				696,948		696,948	5
10,874				641,862		641,862	6
2,938				381,295		381,295	7
2,975				388,501		388,501	8
2,841				372,505		372,505	9
2,975				387,199	-128	387,071	10
2,902				379,147	-128	379,019	11
2,950				388,241	-10	388,231	12
3,036				398,616	-10	398,606	13
3,072				404,651		404,651	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,056				402,234		402,234	1
4,513				170,563		170,563	2
					6,851	6,851	3
					301	301	4
9,034				432,683		432,683	5
62,377			1,184,785	1,891,647		3,076,432	6
30,918			503,911	923,935		1,427,846	7
37,154			475,270	1,109,309		1,584,579	8
200,334				33,293,894		33,293,894	9
73,585				6,393,533		6,393,533	10
858,071				81,774,915	-13,742	81,761,173	11
796,581				74,635,758	-12,310	74,623,448	12
521,956				53,554,501	5,196,626	58,751,127	13
					-39,428	-39,428	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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.
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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)	
					-39,428	-39,428	1
					-39,428	-39,428	2
3,026				710,773		710,773	3
3,851				495,762		495,762	4
3,873				496,061		496,061	5
3,887				498,026		498,026	6
2,324				297,791		297,791	7
165,803				20,860,385	-54,000	20,806,385	8
3,840				488,639	-4,700	483,939	9
2,557				326,458	-3,060	323,398	10
					-25,860	-25,860	11
					-19,980	-19,980	12
3,977				507,433	-4,600	502,833	13
					-25,920	-25,920	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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.
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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.
1,841				268,526		268,526	1
					-54,531	-54,531	2
					-38,194	-38,194	3
					-23,915	-23,915	4
15,222			1,256,699	443,838	-115,801	1,584,736	5
13,957			10,990,694	7,068,941	-22,625	18,037,010	6
1,274,532			13,571,870	35,037,273	1,106,226	49,715,369	7
56,094				8,561,031		8,561,031	8
82,599			1,867,982	2,511,426		4,379,408	9
2,460				337,670		337,670	10
124			818	3,856		4,674	11
6,289			117,150	195,990		313,140	12
5,653			89,739	172,161		261,900	13
8,309			134,707	253,907		388,614	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: 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.
6,036			91,001	183,428		274,429	1
467,749			10,964,530	14,543,174		25,507,704	2
214			7,718	5,661		13,379	3
537			20,150	16,718		36,868	4
471			13,419	12,344		25,763	5
90,733			2,755,585	2,896,626		5,652,211	6
4,263				598,522		598,522	7
1,463				203,409		203,409	8
2,827				397,944		397,944	9
2,793				394,567		394,567	10
2,020				262,804		262,804	11
2,008				261,311		261,311	12
2,714				336,612		336,612	13
2,964				385,840		385,840	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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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.
992				129,177		129,177	1
2,949				383,692		383,692	2
2,959				378,590		378,590	3
2,925				381,077		381,077	4
1,989				259,201		259,201	5
2,013				263,534		263,534	6
2,032				266,275		266,275	7
3,022				396,323		396,323	8
67,872			397,593	2,159,771	-53,703	2,503,661	9
86,331			502,968	2,575,784	-17,774	3,060,978	10
283				27,313		27,313	11
				-184,173		-184,173	12
32,663				2,746,665	-456,000	2,290,665	13
2,208				323,772		323,772	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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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)	
2,450				354,660		354,660	1
1,074				-23,741		-23,741	2
6,410				603,219	-223,457	379,762	3
6,285				597,124	-223,500	373,624	4
					-40,000	-40,000	5
3,780				480,503		480,503	6
3,818				483,771		483,771	7
3,817				483,808		483,808	8
3,765				478,003		478,003	9
10,977			195,533	336,805		532,338	10
7,266			146,063	225,481		371,544	11
11,173			155,472	338,257		493,729	12
4,183				613,951		613,951	13
4,102				595,496		595,496	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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

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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)	
2,783				408,940		408,940	1
282,903			5,741,968	8,766,050		14,508,018	2
1,070,262			7,645,419	36,256,929	-54,440	43,847,908	3
1,102,601			11,960,312	38,191,047	-12,756	50,138,603	4
9,236			281,727	276,226	-49,000	508,953	5
34,617			4,053,639	1,278,629		5,332,268	6
1,319				126,916		126,916	7
46,800			-48,993	2,995,794		2,946,801	8
11,543			-20,838	958,241	-25	937,378	9
573				34,696	150	34,846	10
-70			-88	-3,476		-3,564	11
5			114	653		767	12
238,775				27,711,167		27,711,167	13
19,968				2,007,934		2,007,934	14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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)	
14,335				1,452,260	429	1,452,689	1
					-39,405	-39,405	2
					-39,405	-39,405	3
30,749,212			-2,792,189	1,176,698,628	-108,565,530	1,065,340,909	4
					671,269	671,269	5
					-299,111,850	-299,111,850	6
					-5,366,248	-5,366,248	7
					7,707,203	7,707,203	8
					82,580,807	82,580,807	9
					147,739,308	147,739,308	10
					99,992,881	99,992,881	11
					-5,764,199	-5,764,199	12
					-37,258	-37,258	13
							14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
							1
				16,821,930		16,821,930	2
					87,502	87,502	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
70,487,195	97,831	332,792	1,015,540,162	3,279,916,340	54,618,779	4,350,075,281	

Schedule Page: 326 Line No.: 1 Column: b

OS1 "EVERGREEN" MEANS MINIMUM OF ONE YEAR, WITH AUTOMATIC ANNUAL RENEWAL THEREAFTER. THE AVAILABILITY AND RELIABILITY OF ENERGY DELIVERED IS ON AN AS-AVAILABLE BASIS.

OS2 LONG-TERM POWER PURCHASE AGREEMENTS WITH RENEWABLE / ALTERNATIVE RESOURCES. "LONG-TERM" MEANS FIVE YEARS OR GREATER. THE AVAILABILITY AND RELIABILITY OF ENERGY DELIVERY MUST MATCH THE DEDICATED FIRM MW AS SPECIFIED IN THE CONTRACT.

OS3 EVERGREEN POWER PURCHASE AGREEMENT WITH RENEWABLE / ALTERNATIVE RESOURCES LESS THAN 100 KW. "EVERGREEN" MEANS MINIMUM OF ONE YEAR, WITH AUTOMATIC ANNUAL RENEWAL THEREAFTER. THE AVAILABILITY AND RELIABILITY OR ENERGY DELIVERED IS ON AN AS-AVAILABLE BASIS.

OS4 LONG-TERM POWER PURCHASE AGREEMENTS WITH RENEWABLE / ALTERNATIVE RESOURCES. "LONG-TERM" MEANS FIVE YEARS OR GREATER. THE AVAILABILITY AND RELIABILITY OF ENERGY DELIVERED IS ON AN AS AVAILABLE BASIS.

OS7 LONG-TERM POWER PURCHASE AGREEMENTS WITH RENEWABLE / ALTERNATIVE RESOURCES. "LONG-TERM" MEANS FIVE YEARS OR GREATER. THE AVAILABILITY AND RELIABILITY OF ENERGY DELIVERY MUST MATCH THE DEDICATED FIRM MW AS SPECIFIED IN THE CONTRACT.

OS8 SCE CUSTOMERS ON THE FRINGE OF SCE'S SERVICE AREA.

OS9 TERMINATION AGREEMENT.

OS10 REPLACEMENT FOR LOST ENERGY DUE TO DIVERSION FROM MILL CREEK.

OS11 SETTLEMENT FOR GENERATION DEVIATION FROM TRANSMISSION SERVICE SCHEDULE.

OS12 LOWER COLORADO RIVER MULTI-SPECIES CONSERVATION PROGRAM.

OS13 BROKERS

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 6 Column: l

Facilities charges.

Schedule Page: 326 Line No.: 9 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 10 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 11 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 12 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 1 Column: b

LF 5 - TERMINATION DATE: 09/30/2017.

Schedule Page: 326.1 Line No.: 3 Column: b

OS 12 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 9 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1   Line No.: 9   Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1   Line No.: 10   Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1   Line No.: 10   Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1   Line No.: 11   Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1   Line No.: 11   Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1   Line No.: 12   Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1   Line No.: 12   Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1   Line No.: 13   Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1   Line No.: 13   Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1   Line No.: 14   Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1   Line No.: 14   Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.2   Line No.: 2   Column: l
Sale of Gas.
Schedule Page: 326.2   Line No.: 3   Column: l
Sale of Gas.
Schedule Page: 326.2   Line No.: 5   Column: l
Sale of Gas.
Schedule Page: 326.2   Line No.: 6   Column: l
RA Capacity.
Schedule Page: 326.2   Line No.: 7   Column: l
Transportation. Net Gas Purchases Plus Imbalances.
Schedule Page: 326.2   Line No.: 8   Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense. Sale of Gas.
Schedule Page: 326.2   Line No.: 9   Column: l
Sale of Gas. Net Gas Purchases Plus Imbalances.
Schedule Page: 326.2   Line No.: 10   Column: l
Transportation. Net Gas Purchases Plus Imbalances.
Schedule Page: 326.2   Line No.: 11   Column: l
Sale of Gas.
Schedule Page: 326.2   Line No.: 12   Column: l
Sale of Gas.
Schedule Page: 326.3   Line No.: 2   Column: b
OS 10 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.3   Line No.: 8   Column: l
RA Capacity.
Schedule Page: 326.3   Line No.: 10   Column: l
RA Capacity.
Schedule Page: 326.4   Line No.: 8   Column: l
RA Capacity. Sale of Gas.
Schedule Page: 326.4   Line No.: 11   Column: l
Sale of Gas.

Schedule Page: 326.4 Line No.: 12 Column: l
Sale of Gas.

Schedule Page: 326.4 Line No.: 14 Column: l
RA Capacity. Transportation. Sale of Gas.

Schedule Page: 326.5 Line No.: 1 Column: l
Sale of Gas.

Schedule Page: 326.5 Line No.: 3 Column: l
RA Capacity.

Schedule Page: 326.5 Line No.: 5 Column: l
RA Capacity.

Schedule Page: 326.5 Line No.: 6 Column: l
RA Capacity.

Schedule Page: 326.5 Line No.: 7 Column: l
Sale of Gas.

Schedule Page: 326.5 Line No.: 8 Column: l
Sale of Gas.

Schedule Page: 326.5 Line No.: 10 Column: l
Sale of Gas.

Schedule Page: 326.5 Line No.: 11 Column: l
RA Capacity.

Schedule Page: 326.5 Line No.: 13 Column: l
Sale of Gas.

Schedule Page: 326.6 Line No.: 1 Column: l
RA Capacity.

Schedule Page: 326.6 Line No.: 2 Column: l
Sale of Gas.

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

Schedule Page: 326.6 Line No.: 4 Column: l
RA Capacity. Sale of Gas.

Schedule Page: 326.6 Line No.: 8 Column: l
Sale of Gas.

Schedule Page: 326.6 Line No.: 13 Column: l
Sale of Gas.

Schedule Page: 326.7 Line No.: 2 Column: l
Transportation. Sale of Gas.

Schedule Page: 326.7 Line No.: 3 Column: l
Transportation. Sale of Gas.

Schedule Page: 326.7 Line No.: 4 Column: l
RA Capacity. Transportation. Sale of Gas.

Schedule Page: 326.7 Line No.: 5 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense. Transportation. Sale of Gas.

Schedule Page: 326.7 Line No.: 6 Column: l
Transportation. Sale of Gas.

Schedule Page: 326.7 Line No.: 8 Column: l
RA Capacity.

Schedule Page: 326.7 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense. Transportation. Sale of Gas.

Schedule Page: 326.7 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense. RA Capacity.

Transportation.

Schedule Page: 326.7 Line No.: 11 Column: l

Net Gas Purchases Plus Imbalances.

Schedule Page: 326.7 Line No.: 12 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense. Transportation. Sale of Gas.

Schedule Page: 326.7 Line No.: 13 Column: l

Transportation. Sale of Gas.

Schedule Page: 326.8 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 2 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.8 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.8 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 14 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.9 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 7 Column: b
OS 1 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 7 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.9 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.9 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 11 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.9 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 13 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 2 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 3 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 4 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 7 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 9 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense. RA Capacity. Net Gas Purchases Plus Imbalances.
Schedule Page: 326.10 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.10 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 13 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.10 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.11 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 4 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.11 Line No.: 5 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 7 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 8 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 12 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 14 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 1 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.12 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 2 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.12 Line No.: 3 Column: b

OS 9 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.12 Line No.: 4 Column: b

OS 9 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 4 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.12 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 7 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 10 Column: b
OS 3 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 11 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 12 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 2 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 3 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 4 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 7 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 8 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.13 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.13 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 12 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.13 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 13 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.13 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 14 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.14 Line No.: 1 Column: b

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Schedule Page: 326.14 Line No.: 1 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.14 Line No.: 2 Column: b

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Schedule Page: 326.14 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 5 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 8 Column: b

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Schedule Page: 326.14 Line No.: 8 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.14 Line No.: 9 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 11 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.14 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 14 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 7 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 8 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.15 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.15 Line No.: 10 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 2 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 3 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 4 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 4 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.16 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 5 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.16 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 7 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.16 Line No.: 11 Column: b

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.16 Line No.: 12 Column: b

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Schedule Page: 326.16 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 14 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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OS 4 - Please reference page 326 Line 1 Column (b).

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.17 Line No.: 8 Column: b

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.17 Line No.: 9 Column: b

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OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 12 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 13 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 14 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.18 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 5 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 7 Column: b
OS 1 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 10 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 11 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 12 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 13 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.18 Line No.: 14 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 1 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 2 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 3 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 4 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 7 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 8 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 8 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.19 Line No.: 9 Column: b
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Schedule Page: 326.19 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.19 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.19 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.20 Line No.: 1 Column: b

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Schedule Page: 326.20 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 5 Column: b

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Schedule Page: 326.20 Line No.: 6 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.20 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 8 Column: b

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Schedule Page: 326.20 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 9 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.20 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 11 Column: b

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Schedule Page: 326.20 Line No.: 12 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 13 Column: b

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Schedule Page: 326.20 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 1 Column: b

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Schedule Page: 326.21 Line No.: 1 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.21 Line No.: 2 Column: b

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.21 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.21 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 5 Column: b

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Schedule Page: 326.21 Line No.: 5 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.21 Line No.: 6 Column: b

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.21 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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OS 9 - Please reference page 326 Line 1 Column (b).

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.21 Line No.: 10 Column: b

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OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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Schedule Page: 326.22 Line No.: 2 Column: b

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Schedule Page: 326.22 Line No.: 3 Column: b

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Schedule Page: 326.22 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.22 Line No.: 4 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.22 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.22 Line No.: 6 Column: b

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Schedule Page: 326.22 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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Schedule Page: 326.22 Line No.: 9 Column: b

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Schedule Page: 326.22 Line No.: 10 Column: b

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Schedule Page: 326.22 Line No.: 11 Column: b

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.22 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.23 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.23 Line No.: 1 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.23 Line No.: 2 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.23 Line No.: 3 Column: b
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OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.23 Line No.: 5 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.23 Line No.: 6 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.23 Line No.: 7 Column: b
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OS 3 - Please reference page 326 Line 1 Column (b).
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OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.23 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.23 Line No.: 12 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
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OS 2 - Please reference page 326 Line 1 Column (b).
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OS 4 - Please reference page 326 Line 1 Column (b).
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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 7 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.26 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
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Schedule Page: 326.26 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
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Schedule Page: 326.26 Line No.: 12 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.26 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
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OS 9 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.26 Line No.: 14 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 2 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 5 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 6 Column: b

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 7 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

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Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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OS 4 - Please reference page 326 Line 1 Column (b).
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OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 2 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 3 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 4 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 7 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 9 Column: b
OS 7 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.29 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.29 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 13 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.29 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.30 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 4 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.30 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 5 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.30 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 2 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.31 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 4 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.31 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 5 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.31 Line No.: 6 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 7 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.31 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.31 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 12 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.31 Line No.: 14 Column: b
OS 7 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 1 Column: b
OS 7 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 1 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.32 Line No.: 2 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 2 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.32 Line No.: 3 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 3 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.32 Line No.: 4 Column: l
California ISO Costs.
Schedule Page: 326.32 Line No.: 5 Column: l
Independent Evaluator Costs.
Schedule Page: 326.32 Line No.: 6 Column: l
Various Energy Settlement Refunds.
Schedule Page: 326.32 Line No.: 7 Column: l
Capital Lease under GAAP.
Schedule Page: 326.32 Line No.: 8 Column: l
Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.
Schedule Page: 326.32 Line No.: 9 Column: l
Unrealized Gain / Loss on Financial Futures or Options.
Schedule Page: 326.32 Line No.: 10 Column: l
Realized Gain / Loss on Financial Futures or Options.
Schedule Page: 326.32 Line No.: 11 Column: l
Unrealized Gain / Loss on Financial Futures or Options.
Schedule Page: 326.32 Line No.: 12 Column: l

Renewable Energy Credits.

Schedule Page: 326.32 Line No.: 13 Column: l

Remat/Biomat Application Fees.

Schedule Page: 326.33 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	City of Pasadena	Various	City of Pasadena	AD
2	City of Riverside	Various	City of Riverside	OLF
3	City of Riverside	Various	City of Riverside	AD
4	City of Riverside	Various	City of Riverside	OLF
5	City of Riverside	Various	City of Riverside	AD
6	City of Riverside	Various	City of Riverside	OLF
7	City of Riverside	Various	City of Riverside	AD
8	City of Riverside	Various	City of Riverside	OLF
9	City of Riverside	Various	City of Riverside	AD
10	City of Vernon	Various	City of Vernon	OLF
11	City of Vernon	Various	City of Vernon	OLF
12	City of Vernon	Various	City of Vernon	OLF
13	City of Azusa	Various	City of Azusa	OLF
14	City of Azusa	Various	City of Azusa	AD
15	City of Azusa	Various	City of Azusa	OLF
16	City of Azusa	Various	City of Azusa	AD
17	City of Azusa	City of Pasadena	City of Azusa	OLF
18	City of Azusa	City of Pasadena	City of Azusa	AD
19	City of Azusa	Various	City of Azusa	OLF
20	City of Azusa	Various	City of Azusa	AD
21	City of Azusa	Various	City of Azusa	AD
22	City of Colton	Various	City of Colton	OLF
23	City of Colton	Various	City of Colton	AD
24	City of Colton	Various	City of Colton	OLF
25	City of Colton	Various	City of Colton	AD
26	City of Colton	Various	City of Colton	OLF
27	City of Colton	Various	City of Colton	AD
28	City of Colton	Various	City of Colton	OLF
29	City of Colton	Various	City of Colton	AD
30	City of Colton	Various	City of Colton	AD
31	City of Banning	Various	City of Banning	OLF
32	City of Banning	Various	City of Banning	AD
33	City of Banning	Various	City of Banning	OLF
34	City of Banning	Various	City of Banning	AD
	TOTAL			

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	City of Banning	Various	City of Banning	OLF
2	City of Banning	Various	City of Banning	AD
3	City of Banning	Various	City of Banning	OLF
4	City of Banning	Various	City of Banning	AD
5	Department of Water Resources	Various	Department of Water Resources	OLF
6	Department of Water Resources	Various	Department of Water Resources	OLF
7	Department of Water Resources	Various	Department of Water Resources	OLF
8	Reliant Energy Coolwater, LLC	Alta Power Generation	ISO	OLF
9	Reliant Energy Mandalay, LLC	Ocean Vista Power Generation	ISO	OLF
10	Reliant Energy Ormond Bch, LLC	Ormond Beach Generation	ISO	OLF
11	A.E.S. Huntington Bch. L.L.C.	A.E.S. Huntington Beach	ISO	OLF
12	High Desert Power Trust	Various	High Desert Power Trust	OLF
13	Inland Empire Energy Center	Various	Inland Empire Energy Center	OLF
14	Department of Water Resources	Various	Department of Water Resources	OLF
15	Department of Water Resources	Various	Department of Water Resources	OLF
16	Department of Water Resources	Various	Department of Water Resources	OLF
17	Department of Water Resources	Various	Department of Water Resources	OLF
18	Department of Water Resources	Various	Department of Water Resources	OLF
19	Metropolitan Water District	Department of Water Resources	Metropolitan Water District	OLF
20	City of Los Angeles	Various	City of Los Angeles	OLF
21	City of Los Angeles	Various	City of Los Angeles	AD
22	Sthwest Trans Elec Pwr Coop/AEPCO	Various	Sthwest Trans Elec Pwr Coop/AEPCO	OLF
23	Southern California Water Company	Various	Southern California Water Co	OLF
24	M-S-R Public Power Authority	Various	Pacific Gas & Electric Company	OLF
25	City of Azusa	Various	City of Azusa	OLF
26	City of Riverside	Various	City of Riverside	OLF
27	City of Banning	Various	City of Banning	OLF
28	City of Banning	Various	City of Banning	AD
29	City of Azusa	Various	City of Azusa	OLF
30	City of Azusa	Various	City of Azusa	AD
31	City of Colton	Various	City of Colton	OLF
32	City of Colton	Various	City of Colton	AD
33	Southern California Water Company	Southern California Water Co	Southern California Water Company	OLF
34	Southern California Water Company	Southern California Water Co	Southern California Water Company	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
2	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
3	City of Corona	Various	City of Corona	OLF
4	City of Corona	Various	City of Corona	AD
5	Department of Water Resources	Various	Department of Water Resources	OLF
6	Department of Water Resources	Various	Department of Water Resources	AD
7	Department of Water Resources	Various	Department of Water Resources	OLF
8	Department of Water Resources	Various	Department of Water Resources	AD
9	Department of Water Resources	Various	Department of Water Resources	OLF
10	Department of Water Resources	Various	Department of Water Resources	AD
11	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	OLF
12	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	AD
13	City of Corona	Various	City of Corona	OLF
14	City of Corona	Various	City of Corona	AD
15	City of Corona	Various	City of Corona	OLF
16	City of Corona	Various	City of Corona	AD
17	City of Moreno Valley	Various	City of Moreno Valley	OLF
18	City of Moreno Valley	Various	City of Moreno Valley	AD
19	City of Corona	Various	City of Corona	OLF
20	City of Corona	Various	City of Corona	AD
21	City of Moreno Valley	Various	City of Moreno Valley	OLF
22	City of Moreno Valley	Various	City of Moreno Valley	AD
23	City of Moreno Valley	Various	City of Moreno Valley	OLF
24	City of Moreno Valley	Various	City of Moreno Valley	AD
25	City of Moreno Valley	Various	City of Moreno Valley	OLF
26	City of Moreno Valley	Various	City of Moreno Valley	AD
27	City of Moreno Valley	Various	City of Moreno Valley	OLF
28	City of Moreno Valley	Various	City of Moreno Valley	AD
29	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
30	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
31	City of Moreno Valley	Various	City of Moreno Valley	OLF
32	City of Moreno Valley	Various	City of Moreno Valley	AD
33	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
34	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
	TOTAL			

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Sthwest Trans Elec Pwr Coop/AEPCO	Various	City of Anza	OLF
2	Sthwest Trans Elec Pwr Coop/AEPCO	Various	City of Anza	AD
3	City of Corona	Various	City of Corona	OLF
4	City of Corona	Various	City of Corona	AD
5	Arizona Public Service	Various	Arizona Public Service	OLF
6	Arizona Public Service	Various	Arizona Public Service	AD
7	City of Victorville	Various	City of Victorville	OLF
8	City of Victorville	Various	City of Victorville	AD
9	City of Victorville	Various	City of Victorville	OLF
10	City of Victorville	Various	City of Victorville	AD
11	City of Moreno Valley	Various	City of Moreno Valley	OLF
12	City of Moreno Valley	Various	City of Moreno Valley	AD
13	City of Colton	Various	City of Colton	OLF
14	Department of Water Resources	Various	Department of Water Resources	OLF
15	Department of Water Resources	Various	Department of Water Resources	AD
16	Department of Water Resources	Various	Department of Water Resources	OLF
17	Department of Water Resources	Various	Department of Water Resources	AD
18	Department of Water Resources	Various	Department of Water Resources	OLF
19	Department of Water Resources	Various	Department of Water Resources	AD
20	Sthwest Trans Elec Pwr Coop/AEPCO	Various	Sthwest Trans Elec Pwr Coop/AEPC	OLF
21	Sthwest Trans Elec Pwr Coop/AEPCO	Various	Sthwest Trans Elec Pwr Coop/AEPC	AD
22	Southern California Water Company	Various	Southern California Water Company	OLF
23	Southern California Water Company	Various	Southern California Water Company	AD
24	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
25	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
26	City of Corona	Various	City of Corona	OLF
27	City of Corona	Various	City of Corona	AD
28	Department of Water Resources	Various	Department of Water Resources	OLF
29	Department of Water Resources	Various	Department of Water Resources	AD
30	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	OLF
31	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	AD
32	City of Moreno Valley	Various	City of Moreno Valley	OLF
33	City of Moreno Valley	Various	City of Moreno Valley	AD
34	City of Victorville	Various	City of Victorville	OLF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	City of Victorville	Various	City of Victorville	AD
2	City of Victorville	Various	City of Victorville	OLF
3	City of Victorville	Various	City of Victorville	AD
4	ISO Wheeling	N/A	N/A	OS
5	Mojave Solar LLC	Mojave Solar	ISO	OLF
6	City of Industry	Various	City of Industry	OLF
7				
8	Rounding			
9				
10				
11				
12				
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23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
317	Rio Hondo	Goodrich				1
390.2	Mead	Vista	30			2
390.2	Mead	Vista	30			3
391.2	Victorville-Lugo	Vista	156			4
391.2	Victorville-Lugo	Vista	156			5
392.2	Victorville-Lugo	Vista	12			6
392.2	Victorville-Lugo	Vista	12			7
393.2	San Onofre	Vista	42			8
393.2	San Onofre	Vista	42			9
207.26	Mead	Laguna Bell	26			10
360.2	Victorville-Lugo	Laguna Bell	75			11
359.1	Laguna Bell	Vernon				12
373	Victorville-Lugo	Rio Hondo	4			13
373	Victorville-Lugo	Rio Hondo	4			14
372	Mead	Rio Hondo	4			15
372	Mead	Rio Hondo	4			16
374	Victorville-Lugo	Rio Hondo	14			17
374	Victorville-Lugo	Rio Hondo	14			18
375	Mead / Rio Hondo	Mead / Rio Hondo	8			19
375	Mead / Rio Hondo	Mead / Rio Hondo	8			20
376	Sylmar	Rio Hondo	10			21
362	Victorville-Lugo	Vista	3			22
362	Victorville-Lugo	Vista	3			23
361	Mead	Vista	3			24
361	Mead	Vista	3			25
363	Victorville-Lugo	Vista	18			26
363	Victorville-Lugo	Vista	18			27
365	Devers	Vista				28
365	Devers	Vista				29
364	IPC/Sylmar	Vista	3			30
379	Victorville-Lugo	Devers	3			31
379	Victorville-Lugo	Devers	3			32
378	Mead	Devers	2			33
378	Mead	Devers	2			34
			5,397	**6,219,728**	**6,177,384**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
381	Devers	Devers	15			1
381	Devers	Devers	15			2
380	Victorvle-Lugo-Ban	Ban / Victorvle-Lugo	5			3
380	Victorvle-Lugo-Ban	Ban / Victorvle-Lugo	5			4
113	El Dorado	Vincent	235			5
112.3	Devil Canyon	Calectric	120			6
342	Mohave	Vincent	28			7
402	Cool Water	Kramer				8
401	Mandalay	Santa Clara				9
404	Ormond Beach	Moorpark				10
403	Huntington Beach	Ellis				11
Vol. 6, SA #11	Victor Substation	High Desert				12
470	Valley Sub	Inlnd Empr Enrgy Ctr				13
Vol. 6, SA #35	Bailey-Oso	Various	17			14
Vol. 6, SA #34	Pastoria-Pardee	Various	82			15
Vol. 6, SA #31	Edmonston-Pastoria	Vincent	787			16
Vol. 6, SA #32	Vincent	Various	152			17
Vol. 6, SA #33	Bailey-Sub	Various	72			18
443	Vincent	Julian Hinds				19
219	Various	Various	368			20
219	Various	Various	368			21
131	Mead	Mountain Center	10			22
349.8	Various	Various				23
339	Victorville-Lugo	Midway	150			24
Vol. 5, SA #2	Rio Hondo	Azusa				25
Vol. 5, SA #5	Vista	Riverside City Limit		2,263,456	2,254,177	26
Vol. 5, SA #3	Near Devers	Banning		151,311	146,772	27
Vol. 5, SA #3	Near Devers	Banning				28
Vol. 5, SA #2	Rio Hondo	Azusa		206,016	202,493	29
Vol. 5, SA #2	Rio Hondo	Azusa				30
Vol. 5, SA #1	Vista	City of Colton		360,079	358,494	31
Vol. 5, SA #1	Vista	City of Colton				32
Vol. 5, SA #4	Victor and Vista Sub	Cttnwood & Zanja Sub	39	151,440	145,944	33
Vol. 5, SA #4	Victor and Vista Sub	Cttnwood & Zanja Sub	39			34
			5,397	**6,219,728**	**6,177,384**	

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.
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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.
Vol. 5, SA #48	Walnut Sub 230 kV Bs	Indstry-Old Rnch Rd.		24,936	23,715	1
Vol. 5, SA #48	Walnut Sub 230 kV Bs	Indstry-Old Rnch Rd.				2
Vol. 5, SA #77	Mira Loma	Crossing Bus. Ctr.		22,671	21,600	3
Vol. 5, SA #77	Mira Loma	Crossing Bus. Ctr.				4
Vol. 5, SA #56	Vista	Cherry Valley Stn		387	360	5
Vol. 5, SA #56	Vista	Cherry Valley Stn				6
Vol. 5, SA #57	Vista	Crafton Hills Stn		8,277	8,211	7
Vol. 5, SA #57	Vista	Crafton Hills Stn				8
Vol. 5, SA #58	San Bernardino	Greenspot Station	4	6,694	6,573	9
Vol. 5, SA #58	San Bernardino	Greenspot Station	4			10
Vol. 5, SA #89	Etiwanda	Cty of Rncho Cucamn		74,854	74,323	11
Vol. 5, SA #89	Etiwanda	Cty of Rncho Cucamn				12
Vol. 5,SA #130	Mira Loma	Cleargen Sub		12,156	12,028	13
Vol. 5,SA #130	Mira Loma	Cleargen Sub				14
Vol. 5,SA #97	Mira Loma	Corona Pointe		20,933	20,316	15
Vol. 5,SA #97	Mira Loma	Corona Pointe				16
Vol. 5,SA #103	Valley Sub	Moreno Valley		458	453	17
Vol. 5,SA #103	Valley Sub	Moreno Valley				18
Vol. 5,SA #125	Mira Loma	Corona Dos Lagos	1	22,585	21,088	19
Vol. 5,SA #125	Mira Loma	Corona Dos Lagos	1			20
Vol. 5,SA #115	Valley Sub	Moreno Valley		16,097	15,807	21
Vol. 5,SA #115	Valley Sub	Moreno Valley				22
Vol. 5,SA #117	Valley Sub	Moreno Valley	1	19,470	19,181	23
Vol. 5,SA #117	Valley Sub	Moreno Valley	1			24
Vol. 5,SA #143	Valley Sub	Moreno Valley	1	13,297	12,941	25
Vol. 5,SA #143	Valley Sub	Moreno Valley	1			26
Vol. 5,SA #128	Valley Sub	Moreno Valley		7,300	7,143	27
Vol. 5,SA #128	Valley Sub	Moreno Valley				28
Vol. 5,SA #152	Chino Sub,220kV Bus	Indstry/Wddghm Way	2	9,712	9,182	29
Vol. 5,SA #152	Chino Sub,220kV Bus	Indstry/Wddghm Wa	2			30
Vol. 5,SA #149	Valley Sub	Moreno Valley	12	95,912	95,500	31
Vol. 5,SA #149	Valley Sub	Moreno Valley	12			32
Vol. 5,SA #165	Walnut Sub,220kV bus	IndstryAnheimPuente	2	1,335	1,320	33
Vol. 5,SA #165	Walnut Sub,220kV bus	IndstryAnheimPuente	2			34
			5,397	**6,219,728**	**6,177,384**	

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.
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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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Vol. 5,SA #179	Mountain Center	Anza	1	61,791	56,960	1
Vol. 5,SA #179	Mountain Center	Anza	1			2
Vol. 5,SA #151	Mira Loma	Corona Sunkist	1	4,902	4,778	3
Vol. 5,SA #151	Mira Loma	Corona Sunkist	1			4
Vol. 5,SA #193	Various	Various		48,361	46,115	5
Vol. 5,SA #193	Various	Various				6
Vol. 5,SA #218	Victor Sub	City of Victorville		19,081	18,625	7
Vol. 5,SA #218	Victor Sub	City of Victorville				8
Vol. 5,SA #231	Victor Sub	City of Victorville		70,802	68,961	9
Vol. 5,SA #231	Victor Sub	City of Victorville				10
Vol. 5,SA #695	Valley Sub	Moreno Valley	1	43,190	42,230	11
Vol. 5,SA #695	Valley Sub	Moreno Valley	1			12
361/362/363/3	Various	Various				13
Vol. 6, SA#33	Bailey-Oso	Edmnstn Pmpng Plant	72	1,199,110	1,199,110	14
Vol. 6, SA#33	Bailey-Oso	Edmnstn Pmpng Plant	72	374,328	374,328	15
Vol. 6, SA#32	Edmonston-Pastoria	Pearblssm Pmpg Plant	152	119,620	119,620	16
Vol. 6, SA#32	Edmonston-Pastoria	Pearblssm Pmpg Plant	152	28,869	28,869	17
Vol. 6, SA#31	Vincent	Oso Pumping Plant	787	92,837	92,837	18
Vol. 6, SA#31	Vincent	Oso Pumping Plant	787	33,466	33,466	19
131	Mead	Mountain Center	10	90	90	20
131	Mead	Mountain Center	10	30	30	21
Vol. 5, SA #4	Victor and Vista Sub	Cottnwood&Zanja Sub	39	107,382	107,382	22
Vol. 5, SA #4	Victor and Vista Sub	Cottnwood&Zanja Sub	39	40,987	40,987	23
Vol. No. 5	Various	Various		31,232	31,232	24
Vol. No. 5	Various	Various		9,132	9,132	25
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		60,296	60,296	26
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		19,280	19,280	27
Vol.	Various	Various		10,665	10,665	28
Vol.	Various	Various		2,822	2,822	29
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		57,150	57,150	30
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		17,112	17,112	31
Vol. 5,SA #103	Valley Sub	Moreno Vly Iris Ave	3	142,105	142,105	32
Vol. 5,SA #103	Valley Sub	Moreno Vly Iris Ave	3	42,045	42,045	33
Vol. No. 6	Victor Sub	Victrvil 12kV Intrct		67,723	67,723	34
			5,397	**6,219,728**	**6,177,384**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Vol. No. 6	Victor Sub	Victrvil 12kV Intrct		19,704	19,704	1
Vol. No. 6	Victor Sub	SCE'sCement33kV line				2
Vol. No. 6	Victor Sub	SCE'sCement33kV line				3
N/A	N/A	N/A				4
489.1.0	Sunlot	Kramer				5
Vol.5, SA #737	Walnut Sub	Puente Sub		6,241	6,110	6
						7
				-1	-1	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
			5,397	**6,219,728**	**6,177,384**	

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.
				1
1,681,200			1,681,200	2
				3
8,742,240			8,742,240	4
				5
672,480			672,480	6
				7
1,246,438		2,164	1,248,602	8
				9
1,438,060			1,438,060	10
616,440			616,440	11
265,776		30,252	296,028	12
224,160			224,160	13
				14
224,160			224,160	15
				16
784,560			784,560	17
				18
448,320			448,320	19
				20
				21
168,120			168,120	22
				23
168,120			168,120	24
				25
1,008,720			1,008,720	26
				27
786,970			786,970	28
				29
				30
168,120			168,120	31
				32
112,080			112,080	33
				34
76,926,149	**0**	**5,468,302**	**82,394,451**	

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
280,200			280,200	3
				4
				5
43,200			43,200	6
151,200			151,200	7
		945,624	945,624	8
		209,706	209,706	9
		1,732,280	1,732,280	10
		402,148	402,148	11
		264,133	264,133	12
		42,492	42,492	13
		35,472	35,472	14
		41,172	41,172	15
		93,972	93,972	16
		267,600	267,600	17
		71,400	71,400	18
				19
20,622,720			20,622,720	20
				21
646,700			646,700	22
194,947			194,947	23
1,751,250			1,751,250	24
125,244		87	125,331	25
1,281,672		16,191	1,297,863	26
293,451		26,040	319,491	27
25,844		2,367	28,211	28
158,959		51,472	210,431	29
14,123		4,679	18,802	30
219,804		31,815	251,619	31
18,956		2,892	21,848	32
434,534		175,415	609,949	33
39,578		17,186	56,764	34
76,926,149	**0**	**5,468,302**	**82,394,451**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
61,776		79	61,855	1
5,616		7	5,623	2
120,290		57,858	178,148	3
9,494		5,260	14,754	4
26,950		103	27,053	5
2,450		9	2,459	6
194,953		103	195,056	7
17,723		9	17,732	8
305,800		103	305,903	9
27,800		9	27,809	10
25,482		107	25,589	11
1,882		10	1,892	12
12,991		84	13,075	13
1,175		8	1,183	14
49,973		889	50,862	15
4,014		81	4,095	16
28,798		79	28,877	17
2,618		7	2,625	18
59,818		79	59,897	19
3,975		7	3,982	20
74,479		84	74,563	21
5,714		8	5,722	22
93,610		84	93,694	23
7,071		8	7,079	24
59,647		80	59,727	25
4,524		7	4,531	26
37,791		84	37,875	27
2,554		8	2,562	28
40,670		80	40,750	29
3,660		7	3,667	30
170,631		80	170,711	31
11,526		7	11,533	32
11,220		82	11,302	33
1,020		7	1,027	34
76,926,149	**0**	**5,468,302**	**82,394,451**	

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

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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
37,893		80	37,973	1
2,670		7	2,677	2
13,709		80	13,789	3
1,240		7	1,247	4
180,057		4,613	184,670	5
16,128		419	16,547	6
121,770		80	121,850	7
11,070		7	11,077	8
200,439		78	200,517	9
17,073		7	17,080	10
160,616		87	160,703	11
10,150		7	10,157	12
				13
		83,938	83,938	14
		26,203	26,203	15
		8,373	8,373	16
		2,021	2,021	17
		6,499	6,499	18
		2,343	2,343	19
		6,806	6,806	20
		2,269	2,269	21
		17,181	17,181	22
		6,558	6,558	23
		5,622	5,622	24
		1,644	1,644	25
		10,853	10,853	26
		3,470	3,470	27
		747	747	28
		198	198	29
		10,287	10,287	30
		3,080	3,080	31
		25,579	25,579	32
		7,568	7,568	33
		12,190	12,190	34
76,926,149	**0**	**5,468,302**	**82,394,451**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		3,547	3,547	1
				2
				3
29,596,169			29,596,169	4
		683,492	683,492	5
11,124		286	11,410	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
76,926,149	**0**	**5,468,302**	**82,394,451**	

Schedule Page: 328 Line No.: 1 Column: h

Billing Demand N/A

Schedule Page: 328 Line No.: 1 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 2 Column: d

OLF - 180 Days Notice

Schedule Page: 328 Line No.: 2 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 3 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 4 Column: d

OLF - 180 Days Notice

Schedule Page: 328 Line No.: 4 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 5 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 6 Column: d

OLF - 180 Days Notice

Schedule Page: 328 Line No.: 6 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 7 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 8 Column: d

OLF - 180 Days Notice

Schedule Page: 328 Line No.: 8 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 9 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 10 Column: d

OLF - Hoover PSC

Schedule Page: 328 Line No.: 10 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 11 Column: d

OLF - 12/31/02 / Perm. removed from service

Schedule Page: 328 Line No.: 11 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 12 Column: d

OLF - 2 Years Notice

Schedule Page: 328 Line No.: 12 Column: h

Billing Demand N/A

Schedule Page: 328 Line No.: 12 Column: m

Interconnection Service Charges.

Schedule Page: 328 Line No.: 13 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 13 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 14 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 15 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 15 Column: m

Customer charge per agreement.

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

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 17 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 17 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 18 Column: m

Revenue received in current year for prior year's service period.

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

OLF - 1 Year Notice

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

Customer charge per agreement.

Schedule Page: 328 Line No.: 20 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 21 Column: m

Revenue received in current year for prior year's service period.

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

OLF - 1 Year Notice

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

Customer charge per agreement.

Schedule Page: 328 Line No.: 23 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 24 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 24 Column: m

Customer charge per agreement.

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

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 26 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 26 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 27 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 28 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 28 Column: h

Billing Demand 14.04

Schedule Page: 328 Line No.: 28 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 29 Column: h

Billing Demand 14.04

Schedule Page: 328 Line No.: 29 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 30 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 31 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 31 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 32 Column: m
Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 33 Column: d
OLF - 1 Year Notice

Schedule Page: 328 Line No.: 33 Column: m
Customer charge per agreement.

Schedule Page: 328 Line No.: 34 Column: m
Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 1 Column: d
OLF - 1 Year Notice

Schedule Page: 328.1 Line No.: 1 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 2 Column: m
Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 3 Column: d
OLF - 1 Year Notice

Schedule Page: 328.1 Line No.: 3 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 4 Column: m
Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 5 Column: d
OLF - 12/31/20

Schedule Page: 328.1 Line No.: 5 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 6 Column: d
OLF - Plant Life

Schedule Page: 328.1 Line No.: 6 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 7 Column: d
OLF - Plant Life

Schedule Page: 328.1 Line No.: 7 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 8 Column: d
OLF - 12/31/23 / Take Serv

Schedule Page: 328.1 Line No.: 8 Column: h
Billing Demand N/A

Schedule Page: 328.1 Line No.: 8 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.1 Line No.: 9 Column: d
OLF - 12/31/04 / Take Serv

Schedule Page: 328.1 Line No.: 9 Column: h
Billing Demand N/A

Schedule Page: 328.1 Line No.: 9 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.1 Line No.: 10 Column: d
OLF - 12/31/07 / Take Serv

Schedule Page: 328.1 Line No.: 10 Column: h
Billing Demand N/A

Schedule Page: 328.1 Line No.: 10 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.1 Line No.: 11 Column: d

OLF - 12/31/03 / Cust. Termin.

Schedule Page: 328.1 Line No.: 11 Column: h

Billing Demand N/A

Schedule Page: 328.1 Line No.: 11 Column: m

Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.1 Line No.: 12 Column: d

OLF - 30 Days Notice

Schedule Page: 328.1 Line No.: 12 Column: h

Billing Demand N/A

Schedule Page: 328.1 Line No.: 12 Column: m

Edison's share of statewide congestion charges collected by the CAISO for congestion in the Edison control area caused by scheduling coordinators.

Schedule Page: 328.1 Line No.: 13 Column: d

OLF - 30 Days Notice

Schedule Page: 328.1 Line No.: 13 Column: h

Billing Demand N/A

Schedule Page: 328.1 Line No.: 13 Column: m

Edison's share of statewide congestion charges collected by the CAISO for congestion in the Edison control area caused by scheduling coordinators.

Schedule Page: 328.1 Line No.: 14 Column: d

OLF - 1/1/2035

Schedule Page: 328.1 Line No.: 14 Column: m

Interconnection Service Charges.

Schedule Page: 328.1 Line No.: 15 Column: d

OLF - 1/1/2035

Schedule Page: 328.1 Line No.: 15 Column: m

Interconnection Service Charges.

Schedule Page: 328.1 Line No.: 16 Column: d

OLF - 1/1/2035

Schedule Page: 328.1 Line No.: 16 Column: m

Interconnection Service Charges.

Schedule Page: 328.1 Line No.: 17 Column: d

OLF - 1/1/2035

Schedule Page: 328.1 Line No.: 17 Column: m

Interconnection Service Charges.

Schedule Page: 328.1 Line No.: 18 Column: d

OLF - 1/1/2035

Schedule Page: 328.1 Line No.: 18 Column: m

Interconnection Service Charges.

Schedule Page: 328.1 Line No.: 19 Column: d

OLF - 9/30/17

Schedule Page: 328.1 Line No.: 19 Column: h

Billing Demand N/A

Schedule Page: 328.1 Line No.: 19 Column: m

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 20 Column: d

OLF - Term. Service

Schedule Page: 328.1 Line No.: 20 Column: m

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 21 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 22 Column: d
OLF - 10 Year Notice
Schedule Page: 328.1 Line No.: 22 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 23 Column: d
OLF - 2 Year Notice
Schedule Page: 328.1 Line No.: 23 Column: h
Billing Demand 34/5
Schedule Page: 328.1 Line No.: 23 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 24 Column: d
OLF - 5 Year Notice
Schedule Page: 328.1 Line No.: 24 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 25 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 25 Column: h
Billing Demand 48.70
Schedule Page: 328.1 Line No.: 25 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 26 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 26 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 26 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 27 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 27 Column: h
Billing Demand 36.40
Schedule Page: 328.1 Line No.: 27 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 28 Column: h
Billing Demand 36.40
Schedule Page: 328.1 Line No.: 28 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 29 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 29 Column: h
Billing Demand 48.70
Schedule Page: 328.1 Line No.: 29 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 30 Column: h
Billing Demand 48.70
Schedule Page: 328.1 Line No.: 30 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 31 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 31 Column: h
Billing Demand 67.70
Schedule Page: 328.1 Line No.: 31 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 32 Column: h

Billing Demand 67.70

Schedule Page: 328.1 Line No.: 32 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 33 Column: d

OLF - 1 Year Notice

Schedule Page: 328.1 Line No.: 33 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 34 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 1 Column: d

OLF - 12/31/32

Schedule Page: 328.2 Line No.: 1 Column: h

Billing Demand 7.2

Schedule Page: 328.2 Line No.: 1 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 2 Column: h

Billing Demand 7.2

Schedule Page: 328.2 Line No.: 2 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 3 Column: d

OLF - 180 Days Notice

Schedule Page: 328.2 Line No.: 3 Column: h

Billing Demand 1.7

Schedule Page: 328.2 Line No.: 3 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 4 Column: h

Billing Demand 1.7

Schedule Page: 328.2 Line No.: 4 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 5 Column: d

OLF - Plant Life

Schedule Page: 328.2 Line No.: 5 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 5 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 6 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 6 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 7 Column: d

OLF - Plant Life

Schedule Page: 328.2 Line No.: 7 Column: h

Billing Demand 3.7

Schedule Page: 328.2 Line No.: 7 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 8 Column: h

Billing Demand 3.7

Schedule Page: 328.2 Line No.: 8 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 9 Column: d

OLF - Plant Life

Schedule Page: 328.2 Line No.: 9 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 10 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 11 Column: d

OLF - 07/21/53

Schedule Page: 328.2 Line No.: 11 Column: h

Billing Demand 3.867

Schedule Page: 328.2 Line No.: 11 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 12 Column: h

Billing Demand 3.867

Schedule Page: 328.2 Line No.: 12 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 13 Column: d

OLF - 11/12/34

Schedule Page: 328.2 Line No.: 13 Column: h

Billing Demand 2.5

Schedule Page: 328.2 Line No.: 13 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 14 Column: h

Billing Demand 2.5

Schedule Page: 328.2 Line No.: 14 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 15 Column: d

OLF - 180 Days Notice

Schedule Page: 328.2 Line No.: 15 Column: h

Billing Demand 3.28

Schedule Page: 328.2 Line No.: 15 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 16 Column: h

Billing Demand 3.28

Schedule Page: 328.2 Line No.: 16 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 17 Column: d

OLF - 04/11/2034

Schedule Page: 328.2 Line No.: 17 Column: h

Billing Demand 1.4

Schedule Page: 328.2 Line No.: 17 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 18 Column: h

Billing Demand 1.4

Schedule Page: 328.2 Line No.: 18 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 19 Column: d

OLF - 5/1/34

Schedule Page: 328.2 Line No.: 19 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 20 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 21 Column: d

OLF - 10/1/34

Schedule Page: 328.2 Line No.: 21 Column: h

Billing Demand 1.5

Schedule Page: 328.2 Line No.: 21 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 22 Column: h

Billing Demand 1.5

Schedule Page: 328.2 Line No.: 22 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 23 Column: d

OLF - 10/31/34

Schedule Page: 328.2 Line No.: 23 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 24 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 25 Column: d

OLF - 11/13/2035

Schedule Page: 328.2 Line No.: 25 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 26 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 27 Column: d

OLF - 3/5/35

Schedule Page: 328.2 Line No.: 27 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 27 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 28 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 28 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 29 Column: d

OLF - 10/03/36

Schedule Page: 328.2 Line No.: 29 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 30 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 31 Column: d

OLF - 7/22/37

Schedule Page: 328.2 Line No.: 31 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 32 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 33 Column: d

OLF - 5/3/37

Schedule Page: 328.2 Line No.: 33 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 34 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 1 Column: d

OLF - 6/1/38

Schedule Page: 328.3 Line No.: 1 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 2 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 3 Column: d

OLF - 6/17/36

Schedule Page: 328.3 Line No.: 3 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 4 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 5 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 5 Column: h

Billing Demand 6.5 / 1.5 / 0.7

Schedule Page: 328.3 Line No.: 5 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 6 Column: h

Billing Demand 6.5 / 1.5 / 0.7

Schedule Page: 328.3 Line No.: 6 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 7 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 7 Column: h

Billing Demand 4.5

Schedule Page: 328.3 Line No.: 7 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 8 Column: h

Billing Demand 4.5

Schedule Page: 328.3 Line No.: 8 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 9 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 9 Column: h

Billing Demand 1.25

Schedule Page: 328.3 Line No.: 9 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 10 Column: h

Billing Demand 1.25

Schedule Page: 328.3 Line No.: 10 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 11 Column: d

OLF - 30 Days Notice

Schedule Page: 328.3 Line No.: 11 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 12 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 13 Column: d

OLF - 1 Year Notice

Schedule Page: 328.3 Line No.: 13 Column: h

Billing Demand N/A

Schedule Page: 328.3 Line No.: 13 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 14 Column: d

OLF - 1/1/2035

Schedule Page: 328.3 Line No.: 14 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 15 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 16 Column: d

OLF - 1/1/2035

Schedule Page: 328.3 Line No.: 16 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 17 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 18 Column: d

OLF - 1/1/2035

Schedule Page: 328.3 Line No.: 18 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 19 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 20 Column: d

OLF - Upon Notice

Schedule Page: 328.3 Line No.: 20 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 21 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 22 Column: d

OLF - 30 Days Notice

Schedule Page: 328.3 Line No.: 22 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 23 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 24 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 24 Column: h

Billing Demand 7.2 / 2 / 2

Schedule Page: 328.3 Line No.: 24 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 25 Column: h

Billing Demand 7.2 / 2 / 2

Schedule Page: 328.3 Line No.: 25 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 26 Column: d

OLF - 30 Days Notice

Schedule Page: 328.3 Line No.: 26 Column: h

Billing Demand 1.7

Schedule Page: 328.3 Line No.: 26 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 27 Column: h

Billing Demand 1.7

Schedule Page: 328.3 Line No.: 27 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 28 Column: d

OLF - Plant Life

Schedule Page: 328.3 Line No.: 28 Column: h

Billing Demand .5

Schedule Page: 328.3 Line No.: 28 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 29 Column: h

Billing Demand .5

Schedule Page: 328.3 Line No.: 29 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 30 Column: d

OLF - 30 Days Notice

Schedule Page: 328.3 Line No.: 30 Column: h

Billing Demand 3.87

Schedule Page: 328.3 Line No.: 30 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 31 Column: h

Billing Demand 3.87

Schedule Page: 328.3 Line No.: 31 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 32 Column: d

OLF - 4/11/2034

Schedule Page: 328.3 Line No.: 32 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 33 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 34 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 34 Column: h

Billing Demand 5.6

Schedule Page: 328.3 Line No.: 34 Column: m

Reliability Services Charge.

Schedule Page: 328.4 Line No.: 1 Column: h

Billing Demand 5.6

Schedule Page: 328.4 Line No.: 1 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.4 Line No.: 2 Column: d

OLF - 180 Days Notice

Schedule Page: 328.4 Line No.: 2 Column: h

Billing Demand 1.25

Schedule Page: 328.4 Line No.: 2 Column: m

Reliability Services Charge.

Schedule Page: 328.4 Line No.: 3 Column: h

Billing Demand 1.25

Schedule Page: 328.4 Line No.: 3 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.4 Line No.: 4 Column: d

OS- Plant Life

Schedule Page: 328.4 Line No.: 4 Column: h

Billing Demand N/A

Schedule Page: 328.4 Line No.: 4 Column: m

Edison's share of statewide wheeling collected by the CAISO from scheduling coordinators.

Schedule Page: 328.4 Line No.: 5 Column: d

OLF - 2/08/2012 / Customer Termin.

Schedule Page: 328.4 Line No.: 5 Column: h

Name of Respondent Southern California Edison Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Billing Demand N/A

Schedule Page: 328.4 Line No.: 5 Column: m

Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.4 Line No.: 6 Column: d

OLF - 12/17/34

Schedule Page: 328.4 Line No.: 6 Column: h

Billing Demand 1.8

Schedule Page: 328.4 Line No.: 6 Column: m

Customer charge plus facility charge per agreement.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1	None.				
2					
3					
4					
5					
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34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	OLF					8,941,137	8,941,137
2	Western Area Power Adme	OLF					92,229	92,229
3	Imperial Irrigation Di	LFP					279,936	279,936
4	Arizona Public Service)	FNS	2,131	2,131		14,525		14,525
5	Bonneville Power Adminn	FNS	6,033,275	6,033,275		14,226,657		14,226,657
6	Morgan Stanley Capital.	FNS	-361,340	-361,340		-409,564		-409,564
7	Nevada Power Company	FNS	173,085	173,085		39,489		39,489
8	PacifiCorp	FNS	460,728	460,728		2,164,387		2,164,387
9	Portland General Electy	FNS	7,553	7,553		7,940		7,940
10	Puget Sound Energy Inc.	FNS						
11	WAPA - Desert SW Region	FNS	4,262	4,262		10,100		10,100
12	Calpine Energy Service	FNS						
13	LA DWP	FNS						
14	TransAlta Energy Marke.	FNS						
15	City of Pasadena	FNS						
16	Department of Energy -E	FNS	-161	-161		-322		-322
	TOTAL		6,178,270	6,178,270		19,584,053	9,313,300	28,897,353

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	EDF Trading North AmerC	FNS	218,880	218,880		399,414		399,414
2	Powerex Corp.	FNS	1,239,050	1,239,050		5,130,378		5,130,378
3	Salt River Project Agrs	FNS	72	72		81		81
4	Constellation Energy C)	FNS						
5	Idaho Power Company (2)	FNS						
6	Shell Energy North Amea	FNS	-1,599,316	-1,599,316		-1,999,145		-1,999,145
7	Sierra Pacific Power Cy	FNS	51	51		113		113
8	Found						-2	-2
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		6,178,270	6,178,270		19,584,053	9,313,300	28,897,353

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

Arizona Public Service Company (APS)

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

OLF-01/01/2017

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

(1) Includes APS O&M Charges

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

Western Area Power Administration (Western) - Blythe

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

OLF-1 Yr Notice

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

(3) Transmission Service Charge to SCE (Contract 10036)

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

Imperial Irrigation Dist. (Salton Sea)

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

(2) Common facilities Operation and Maintenance Charges

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

Arizona Public Service Company (APS)

Schedule Page: 332 Line No.: 5 Column: a

Bonneville Power Administration

Schedule Page: 332 Line No.: 6 Column: a

Morgan Stanley Capital Group Inc.

Schedule Page: 332 Line No.: 9 Column: a

Portland General Electric Energy Company

Schedule Page: 332 Line No.: 12 Column: a

Calpine Energy Services LP

Schedule Page: 332 Line No.: 13 Column: a

Los Angeles Department of Water and Power

Schedule Page: 332 Line No.: 14 Column: a

TransAlta Energy Marketing (US) Inc.

Schedule Page: 332 Line No.: 16 Column: a

Department of Energy - Hoover SCE

Schedule Page: 332.1 Line No.: 1 Column: a

EDF Trading North America, LLC

Schedule Page: 332.1 Line No.: 3 Column: a

Salt River Project Agricultural Improvement & Power Dis

Schedule Page: 332.1 Line No.: 4 Column: a

Constellation Energy Commodities Group Inc (20245)

Schedule Page: 332.1 Line No.: 5 Column: a

Idaho Power Company (20400)

Schedule Page: 332.1 Line No.: 6 Column: a

Shell Energy North America

Schedule Page: 332.1 Line No.: 7 Column: a

Sierra Pacific Power Company

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,737,387
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	5,248,949
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	569,652
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Credit Line/Bank Charges	4,446,324
7	Directors Fees	3,227,225
8	SEC Reports	371,127
9	Planning & Development of Communications Systems	1,358,527
10	Provision for Doubtful Accounts-Non-Energy Billings	-2,989,436
11	Vendor Discounts	-11,239,029
12	Accounting Suspense	1,709,050
13	Miscellaneous	-639,399
14		
15	Payments to CEC/CPUC	11,386,823
16	Admin and General Expense Charged or Paid to Others	-3,489,868
17	Balance Sheet Write-Off	4,896,795
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
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45		
46	TOTAL	18,594,127

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			274,255,084	8,189	274,263,273
2	Steam Production Plant	728			24,212,441	24,213,169
3	Nuclear Production Plant	8,887,427			179,692,146	188,579,573
4	Hydraulic Production Plant-Conventional	32,084,153				32,084,153
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	48,713,247				48,713,247
7	Transmission Plant	287,534,989			677,760	288,212,749
8	Distribution Plant	818,199,400				818,199,400
9	Regional Transmission and Market Operation					
10	General Plant	233,053,442			827,713	233,881,155
11	Common Plant-Electric	16,705				16,705
12	TOTAL	1,428,490,091		274,255,084	205,418,249	1,908,163,424

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	310.2	190				Life Span	
14	311	723	45.00			Life Span	
15	312	1,060	45.00			Life Span	
16	314		45.00			Life Span	
17	315		45.00			Life Span	
18	316	48	45.00			Life Span	
19							
20							
21	NUCLEAR PRODUCTION						
22	SONGS 2 & 3						
23	320.2					License	
24	321					License	
25	322					License	
26	323					License	
27	324					License	
28	325					License	
29							
30							
31	PVNGS 1,2 & 3						
32	320.2		34.00			License	31.50
33	321	173,233	34.00		0.77	License	31.50
34	322	112,735	34.00		0.51	License	31.50
35	323	51,763	34.00		0.49	License	31.50
36	324	26,871	34.00		0.25	License	31.50
37	325	21,273	34.00		0.18	License	31.50
38							
39							
40	HYDRAULIC						
41	37.6	3,323	60.00		2.69	License	34.00
42	331	206,949	56.00	-7.30	2.24	License	37.60
43	332	570,342	65.00	-3.70	2.36	License	32.80
44	333	173,025	55.00	-5.60	2.38	License	34.40
45	334	208,370	40.00	-20.30	4.22	License	28.60
46	335	12,485	60.00	-7.20	2.48	License	35.60
47	336	19,173	44.00	-24.60	4.73	License	29.30
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	OTHER PRODUCTION						
13	340.2	527	31.00		2.91	Life Span	28.60
14	341	84,573	31.00		2.91	Life Span	28.60
15	342	16,524	31.00		2.55	Life Span	28.60
16	343	1,103,443	31.00		2.61	Life Span	28.60
17	344	125,473	31.00		3.00	Life Span	28.60
18	345	182,554	31.00		2.59	Life Span	28.60
19	346	85,267	31.00		2.88	Life Span	28.60
20							
21							
22	TRANSMISSION PLANT						
23	350.2	206,577	60.00		1.67	Judgement	58.00
24	352	686,280	55.00	-35.00	2.53	S 3.0	41.80
25	353	5,237,366	45.00	-15.00	2.66	R 0.5	36.30
26	354	2,259,306	65.00	-60.00	2.30	R 5.0	43.90
27	355	1,008,567	50.00	-72.00	3.43	R 0.5	39.70
28	356	1,481,834	61.00	-80.00	2.63	R 3.0	37.50
29	357	61,087	55.00		1.73	R 3.0	37.60
30	358	268,612	40.00	-15.00	2.65	R2.5	27.20
31	359	194,018	60.00		1.52	SQ	42.50
32							
33							
34	DISTRIBUTION PLANT						
35	360.2	64,753	60.00		1.67	Judgement	58.00
36	361	576,706	42.00	-25.00	3.04	R2.5	27.10
37	362	2,244,271	45.00	-25.00	3.13	R 1.5	32.80
38	364	2,463,386	47.00	-210.00	7.04	L 0.5	36.70
39	365	1,432,987	45.00	-115.00	4.87	R 0.5	33.20
40	366	1,811,861	59.00	-30.00	2.22	R 3.0	42.70
41	367	5,548,405	45.00	-60.00	2.98	R 0.5	36.20
42	368	3,508,639	33.00	-20.00	3.93	R 1.0	22.80
43	369	1,301,407	45.00	-100.00	4.34	R 1.5	30.70
44	370	981,135	20.00	-5.00	5.30	R 3.0	16.20
45	373	872,084	40.00	-30.00	3.10	L 0.5	28.50
46							
47							
48							
49							
50							

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	GENERAL						
13	389.2	3,282	60.00		1.67	Judgement	58.00
14	390	947,106	38.00	-10.00	2.74	R 3.0	25.80
15	391.XXX	697,451	12.00		16.48	Judgement	5.30
16	392.4	2,785	7.00		14.29	Judgement	5.00
17	393	12,675	20.00		5.00	Judgement	18.00
18	394.6	354	10.00		10.00	Judgement	8.00
19	395	100,495	15.00		6.67	Judgement	13.00
20	396	643	15.00	25.00	6.67	Judgement	13.00
21	397	890,958	16.00		9.77	Judgement	14.20
22	398	29,214	20.00		5.00	Judgement	
23							
24							
25	TOTAL	38,074,168					
26							
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50							

Schedule Page: 336 Line No.: 7 Column: e

Includes Acct. 108.105 (Plant Held for Future Use) Accum. Depreciation for Easements/Land Rights.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Regulatory Commission Assessed Expenses				
2	CPUC Applications - Various				
3	FERC Order No. 472				
4	Intervenor Compensation				
5	Outside Legal Svcs & Related Expenses				
6					
7	R.08-11-005, I.09-01-018				
8	2007 MALIBU CANYON FIRE OII		3,595	3,595	
9	LA2009000172				
10					
11	No Docket				
12	2011 FERC GRC-EL PASO TY LA2010000667		319	319	
13					
14	R.11-03-006				
15	2012 DWR REVENUE REQUIREMENT		358	358	
16	LA2011000182				
17					
18	No Docket				
19	2012 GRC - DISABILITY RIGHTS ADVOCATES		7,071	7,071	
20	LA2011000249				
21					
22	A.13-11-003				
23	2015 GENERAL RATE CASE LA2012000405		50,338	50,338	
24					
25	ER12-2287, ER15-499				
26	ALTA WINDPOWER DEVELOPMENT TRANSMISSION		1,323,109	1,323,109	
27	LA2012000331				
28					
29	No Docket				
30	AMERICANS WITH DISABILITIES ACT (ADA)		3,318	3,318	
31	LA2008000720				
32					
33	07-157C, 07-167C				
34	CALIFORNIA MUNI LITIGATION LA2006000235		211,808	211,808	
35					
36	A.08-07-021, D.09-09-047				
37	CEES - CUSTOMER ENERGY EFF & SOLAR GRP		15,822	15,822	
38	LA2010000646				
39					
40	RM10-23				
41	COMPETITIVE TRANSMISSION ISSUES		19,994	19,994	
42	LA2010000526				
43	A.15-07-002				
44	DRP RELATED ISSUES LA2015000179		23,044	23,044	
45					
46	TOTAL		35,128,132	35,128,132	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	A.04-04-008				
2	ECONOMIC DAMAGES (DIRECT) LA2014000002		3,109,000	3,109,000	
3					
4	No Docket				
5	ECONOMIC DAMAGES (INDIRECT) LA2014000001		3,979,655	3,979,655	
6					
7	ER07-830				
8	ELDORADO CONTRACTS		2,991	2,991	
9	LA2007000417				
10					
11	EL00-95-000, EL00-98-000				
12	FERC INVESTIGATION LA2000000853		3,077,816	3,077,816	
13					
14	R.08-08-009				
15	FIT AND SB 32 LEGAL SUPPORT LA2011000149		6,296	6,296	
16					
17	ER11-3697				
18	FORMULA RATE ADMINSTRATION LA2010000986		2,297	2,297	
19					
20	I.15-11-006				
21	HUNTINGTON BEACH VAULT EXPLOSION OII		40,347	40,347	
22	LA2015000427				
23					
24	A.08-11-001 ET AL, R.10-05-006				
25	IMPLEMENTATION OF QF SETTLEMENT		3,864	3,864	
26	LA2012000371				
27					
28	R.04-03-017				
29	INTERCONNECTION ISSUES LA2008000697		93,348	93,348	
30					
31	A.06-08-011, D.07-03-013, EL11-8, EL11-11				
32	ISO/TO/RTO/VARIOUS TRANS & MKT ISSUES		88,513	88,513	
33	LA2006000712				
34					
35	ER03-198-005				
36	MARKET BASED PRICING TRIENNIAL		429	429	
37	LA2004000888				
38					
39	R.04-04-003				
40	MISC. RELIABILITY ISSUES LA2007000712		28,865	28,865	
41					
42	A.13-10-020; EC13-114, EL14-40				
43	MORONGO WEST OF DEVERS INVESTMENT		3,389	3,389	
44	LA2012000363				
45					
46	TOTAL		35,128,132	35,128,132	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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	A.13-11-003, I.12-10-013, A.13-01-016,				
2	A.13-03-005,A.13-03-013, A.13-03-014				
3	NEIL - OUTAGE POLICY CLAIM LA2014000432		1,215,085	1,215,085	
4					
5	A.13-11-003, I.12-10-013, A.13-01-016,				
6	A.13-03-005,A.13-03-013, A.13-03-014				
7	NEIL - PROPERTY DAMAGE POLICY CLAIM		83,728	83,728	
8	LA2014000433				
9					
10	R.04-03-017				
11	NEM ANTITRUST LA2014000357		12,025	12,025	
12					
13	A.14-12-007, I.12-10-013, A.13-01-016,				
14	A.13-03-005,A.13-03-013, A.13-03-014				
15	NUCLEAR FUEL TRADING AGREEMENTS		13,914	13,914	
16	LA2014000271				
17					
18	No Docket				
19	PAINTER FFD OI INVESTIGATION LA2014000038		-32,756	-32,756	
20					
21	No Docket				
22	PEAKERS AQMD VARIANCE: CAISO EMERGENCIES		3,266	3,266	
23	LA2013000707				
24					
25	A.96-08-031				
26	PROCTER & GAMBLE CAPACITY LA1994000788		19	19	
27					
28	No Docket				
29	SAN FRANCISCO OFFICE LA2004001099		2,811	2,811	
30					
31	R.14-05-013				
32	SED CITATION OIR LA2014000301		4,964	4,964	
33					
34	A.09-04-009, A.09-04-007				
35	SENSITIVITY ANALYSIS-DELAYED DECOMM		66,281	66,281	
36	LA2014000525				
37					
38	A.11-004-006				
39	SONGS - TECHNICAL EXPERTS LA2014000003		3,253,885	3,253,885	
40					
41	I.12-10-013,A13-01-016, A.13-03-005,				
42	A.13-03-013, A.13-03-014				
43	SONGS - OII LA2012002218		95,154	95,154	
44					
45					
46	TOTAL		35,128,132	35,128,132	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	A.13-03-013, A.13-03-014				
2	SONGS RSG REG/COMM LIT/INSURANCE		10,981,385	10,981,385	
3	LA2012000335				
4					
5	I.12-10-013,A13-01-016, A.13-03-005,				
6	A.13-03-013, A.13-03-014				
7	SONGS STEAM GEN INSPECTION & REP(NRC)		131,480	131,480	
8	LA2012000150				
9					
10	05-1327, 08-1384				
11	STATION POWER TARIFF LA2008000691		239	239	
12					
13	No Docket				
14	SYNCHRONOUS CONDENSER, EVALUATE RISKS		-42,458	-42,458	
15	LA2014000345				
16					
17	R.09-05-006				
18	TELECOM ADVICE LA2015000028		4,422	4,422	
19					
20	A.06-01-012, A.07-06-031, A.09-08-019,				
21	A.08-02-001, A.07-05-003, R.01-10-024,				
22	R.04-04-025, R.09-07-027,A.11-03-001 ET AL.				
23	TRANSCRIPTS-CPUC (ONLY) LA1990000067		37,291	37,291	
24					
25	EL13-71, EL15-52				
26	WINDING CREEK SOLAR ENFORCEMENT ACTION		239	239	
27	LA2013000342				
28					
29					
30	YEAR END ACCRUALS		1,162,826	1,162,826	
31	PROCUREMENT/EQUIPMENT SERVICES		19,444	19,444	
32	TRANSFERRED TO DECOMMISSIONING TRUST		-2,832,225	-2,832,225	
33					
34	REGULATORY COMMISSION EXPENSES:				
35	ISO FERC FEES - Corporate & Regulatory Acctng		5,282,666	5,282,666	
36	INTERVENOR COMPENSATION		3,568,861	3,568,861	
37					
38	EMPLOYEES SALARIES AND EXPENSES RELATED				
39	TO FORMAL CASES:				
40	FERC Applications				
41	Minor Items (Less than $25,000)				
42					
43					
44					
45					
46	TOTAL		35,128,132	35,128,132	

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
							5
							6
							7
ELECTRIC	928	3,595					8
							9
							10
							11
ELECTRIC	928	319					12
							13
							14
ELECTRIC	928	358					15
							16
							17
							18
ELECTRIC	928	7,071					19
							20
							21
							22
ELECTRIC	928	50,338					23
							24
							25
ELECTRIC	928	1,323,109					26
							27
							28
							29
ELECTRIC	928	3,318					30
							31
							32
							33
ELECTRIC	928	211,808					34
							35
							36
ELECTRIC	928	15,822					37
							38
							39
							40
ELECTRIC	928	19,994					41
							42
							43
ELECTRIC	928	23,044					44
							45
		35,128,132					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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
ELECTRIC	928	3,109,000					2
							3
							4
ELECTRIC	928	3,979,655					5
							6
							7
ELECTRIC	928	2,991					8
							9
							10
							11
ELECTRIC	928	3,077,816					12
							13
							14
ELECTRIC	928	6,296					15
							16
							17
ELECTRIC	928	2,297					18
							19
							20
ELECTRIC	928	40,347					21
							22
							23
							24
ELECTRIC	928	3,864					25
							26
							27
							28
ELECTRIC	928	93,348					29
							30
							31
ELECTRIC	928	88,513					32
							33
							34
							35
ELECTRIC	928	429					36
							37
							38
							39
ELECTRIC	928	28,865					40
							41
							42
ELECTRIC	928	3,389					43
							44
							45
		35,128,132					46

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
ELECTRIC	928	1,215,085					3
							4
							5
							6
ELECTRIC	928	83,728					7
							8
							9
							10
ELECTRIC	928	12,025					11
							12
							13
							14
ELECTRIC	928	13,914					15
							16
							17
							18
ELECTRIC	928	-32,756					19
							20
							21
ELECTRIC	928	3,266					22
							23
							24
							25
ELECTRIC	928	19					26
							27
							28
ELECTRIC	928	2,811					29
							30
							31
ELECTRIC	928	4,964					32
							33
							34
ELECTRIC	928	66,281					35
							36
							37
							38
ELECTRIC	928	3,253,885					39
							40
							41
							42
ELECTRIC	928	95,154					43
							44
							45
		35,128,132					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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
ELECTRIC	928	10,981,385					2
							3
							4
							5
							6
ELECTRIC	928	131,480					7
							8
							9
							10
ELECTRIC	928	239					11
							12
							13
ELECTRIC	928	-42,458					14
							15
							16
							17
ELECTRIC	928	4,422					18
							19
							20
							21
							22
ELECTRIC	928	37,291					23
							24
							25
ELECTRIC	928	239					26
							27
							28
							29
ELECTRIC	928	1,162,826					30
ELECTRIC	928	19,444					31
ELECTRIC	928	-2,832,225					32
							33
							34
ELECTRIC	928	5,282,666					35
ELECTRIC	928	3,568,861					36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		35,128,132					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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. Environmental Health & Safety	
2		General Support Number for PEM Research
3		
4	B. Transmission and Distribution (T&D)	
5		ES&T-EDS Digger Derek
6		ES&T-Electrochemical Energy Storage Lab
7		ES&T-Fleet Effectiveness, Next Gen Drive
8		ES&T-Energy Storage Controls & Monitoring
9		GA-MODEL VALIDATION
10		ES&T-Behind the Meter Energy Storage
11		ES&T-EPRI Program 18 Electric Trans (L)
12		ES&T-EPRI Program 94 Energy Storage (L)
13		GA-Substation Animal Deterrent (L)
14		GA-SA-3 Phase 3 Req Development
15		ES&T-DES System & Controls Eval
16		GA-EPRI data Anlytc Mthds&Demo Link AMI
17		GA-LBNL A/C with VFD Research
18		GA-LBNL 3-Phase Commerical A/C Research
19		GA-CSI4 Advanced Distribution Analytics
20		GA-CSI4 Standard Comm Interface
21		GA-Cable-in-Conduit (CIC) CableTech Eval
22		GA-NCSU Synchro-Phasor Support
23		GA-Phasor Simulator for Op Training
24		GA-SCE Transmission System Volt/Var Ctrl
25		GA-Synchrophasor BAsed Linear Estimator
26		GA-Defending Against Xtreme Contingency
27		California Solar Initiative #4
28		AT TECH DEV - ISGD Decommissioning
29		GA-Remote Street Light Monitor
30		Grid Operator's Monitoring & Ctrl Asst
31		GA-EPRI Distribution Monitoring-15% Rule
32		GA-UCI Microgrid Research
33		ES&T-Adv Storage Sizing Tool
34		GA-Hybrid RT Advanced Modeling
35		GA-IX of 2 Real-Time Simulators
36		ISGD Close-Out
37		ARRA TSP BA
38		EPIC-SCE Administration

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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		GA-Regional Grid Optimization
2		GA-Enchanced Infrastructure Tech Eval
3		ES&T-Distributed Optimized Storage
4		GA-SA3 Phase III Demonstration
5		GA-Beyond the Meter (Phase II)
6		GA-Dynamic Line Rating Demo
7		GA-Next Generation DA
8		GA-Outage Management Demo
9		GA-Distribution Planning and Analysis
10		GA-AVVC of SCE's Transmission System
11		GA-State Esitmation Using PMU
12		GA-Wide-Area Reliability Mgmt & Control
13		GA-Cyber-Intrusion Auto-Response
14		GA-Cyber-Intrusion Auto-Response (IT)
15		EPIC II-SCE Administration
16		GA-Integration of Big Data
17		GA-Proactive Storm Impact Analysis
18		GA-Advanced Grid Capabilities
19		
20	C. Customer Service / End Use	
21		CLSD-GA-PEV Smart Charging
22		GA-Reg Mandates: Submetering Demo
23		GA-Submetering Phase2
24		
25		
26		
27		
28		
29	Total Research and Development	
30		
31		
32		
33		
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
1,083	47,352	920A	48,435		2
					3
					4
	36,681	912A	36,681		5
248,802	37,438	912A	286,240		6
102,906	53,058	912A	155,963		7
7,648	60,062	912A	67,710		8
96,936	67,995	580A	164,931		9
21,744	470	912A	22,214		10
91	388,754	912A	388,845		11
91	266,212	912A	266,303		12
10,999	62,738	580A	73,737		13
1,493	274,478	580A	275,971		14
10,805	253	912A	11,057		15
23,783	1,317	580A	25,100		16
10,177	201	560A	10,378		17
18,790	406	560A	19,196		18
137,374	13,346	580A	150,720		19
32,326	19,596	580A	51,921		20
13,157	19,820	580A	32,977		21
7,011	4,055	560A	11,067		22
51,776	1,172	560A	52,948		23
23,153	200,680	560A	223,833		24
13,763	125,957	560A	139,720		25
2,860	320,192	560A	323,051		26
3,592	26,930	580A	30,522		27
31,520	455,043	912A	486,563		28
18,600	737	580A	19,337		29
26,401	721	560A	27,122		30
997	16,678	580A	17,675		31
27,186	635	580A	27,821		32
15,934	353	912A	16,287		33
4,248	116,782	560A	121,029		34
6,414	97,737	560A	104,151		35
13,653	337,590	912A	351,243		36
263,929	1,001,447	566C	1,265,376		37
125,580	257,278	930R	382,858		38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
786,101	2,874,165	930R	3,660,266		1
25,584	12,707	930R	38,291		2
17,470	87	930R	17,557		3
263,106	531,306	930R	794,412		4
82,328	901,367	930R	983,695		5
54,772	386,010	930R	440,782		6
580,562	873,282	930R	1,453,844		7
66,177	663,136	930R	729,312		8
58,178	223,302	930R	281,480		9
124,418	15,195	930R	139,613		10
22,207	11,746	930R	33,953		11
59,875	188,938	930R	248,812		12
94,570	1,379,040	930R	1,473,610		13
	20,368	930R	20,368		14
181,856	94,688	930R	276,544		15
14,693		930R	14,693		16
77,357	225	930R	77,582		17
87,991	262	930R	88,253		18
					19
					20
	26,109	580A	26,109		21
35,828	287,070	930R	322,899		22
	25,301	930R	25,301		23
					24
					25
					26
					27
					28
4,007,895	12,828,468		16,836,358		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
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	61,578,665		
4	Transmission	63,629,513		
5	Regional Market			
6	Distribution	138,936,391		
7	Customer Accounts	80,656,745		
8	Customer Service and Informational	82,576,197		
9	Sales	5,064,844		
10	Administrative and General	220,656,169		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	653,098,524		
12	Maintenance			
13	Production	13,835,727		
14	Transmission	15,102,039		
15	Regional Market			
16	Distribution	70,825,282		
17	Administrative and General	1,334,910		
18	TOTAL Maintenance (Total of lines 13 thru 17)	101,097,958		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	75,414,392		
21	Transmission (Enter Total of lines 4 and 14)	78,731,552		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	209,761,673		
24	Customer Accounts (Transcribe from line 7)	80,656,745		
25	Customer Service and Informational (Transcribe from line 8)	82,576,197		
26	Sales (Transcribe from line 9)	5,064,844		
27	Administrative and General (Enter Total of lines 10 and 17)	221,991,079		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	754,196,482		754,196,482
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	9,980		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	282,222		
37	Customer Accounts	37,796		
38	Customer Service and Informational			
39	Sales			
40	Administrative and General	89,607		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	419,605		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply	71,630		
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	118,873		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	190,503		
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)	81,610		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	401,095		
58	Customer Accounts (Line 37)	37,796		
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	89,607		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	610,108		610,108
63	Other Utility Departments			
64	Operation and Maintenance	1,556,016		1,556,016
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	756,362,606		756,362,606
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	686,903,453		686,903,453
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	686,903,453		686,903,453
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Expenditures for certain civic, political and miscellaneous	6,596,643		6,596,643
79	Nonutility Operations	5,947,043		5,947,043
80	Miscellaneous Other Accounts	55,420,117		55,420,117
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	67,963,803		67,963,803
96	TOTAL SALARIES AND WAGES	1,511,229,862		1,511,229,862

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

COMMON UTILITY PLANT IN SERVICE

ACCOUNT	BALANCE BEGINNING OF YEAR	ADDITIONS	RETIREMENTS	BALANCE END OF YEAR
Structures and Improvements	$ 1,000,500	$ -	$ -	$ 1,000,500
Office Furniture and Equipment	44,072	-	-	44,072
Transportation Equipment	-	-	-	-
Stores Equipment	11,113	-	-	11,113
Tools, Shop and Garage Equipment	49,234	-	-	49,234
Communication Equipment	11,064	-	-	11,064
Miscellaneous Equipment	-	-	-	-
Total Common Utility Plant in Service	1,115,983	-	-	1,115,983
Construction Work in Progress	-	-	-	-
Total Common Utility Plant	$ 1,115,983	$ -	$ -	$ 1,115,983

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.

CONSTRUCTION WORK in PROGRESS - COMMON UTILITY PLANT

Description of Project	Balance End of Year
Structures and Improvements	$ 4,785,280
Office Furniture and Equipment Acquisitions	-
Transportation Equipment	-
Stores Equipment	-
Tools and Equipment Acquisitions	-
Communication Equipment	-
Miscellaneous Equipment	-
Total Construction Work in Progress Common Utility Plant	$ 4,785,280

DEPARTMENTAL ALLOCATION OF COMMON UTILITY PLANT MADE ON REVENUE BASIS

Total Common Utility Plant, Page 201, line 8		$ 1,115,983
Electric Department	60%	669,590
Gas Department	15%	167,397
Water Department	25%	278,996
		$ 1,115,983

DEPARTMENTAL ALLOCATION OF COMMON UTILITY PLANT MADE ON REVENUE BASIS

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.

Total Common CWIP,Page 201,line 11		$ 4,785,280
Electric Department	60%	2,871,168
Gas Department	15%	717,792
Water Department	25%	1,196,320
		$ 4,785,280

Accumulated Provision for Depreciation of Common Utility Plant

	General Plant Account 119.300	General Other Account 119.400	Total
Balance Beginning of the Year	$ 487,816	$ 49,234	$ 537,050
Depreciation Provision for Year Charged to:			
Depreciation Expense	27,842	-	27,842
Other Clearing Accounts	-	-	-
Net Charges for Plant Retired:			
Book Cost of Plant Retired	-	-	-
Cost of Removal	-	-	-
Salvage	-	-	-
Net Charged for Plant Retired	-	-	-
Other Credits	-	-	-
Total Charged to Depreciation	27,842	-	27,842
Balance End of the Year	$ 515,658	$ 49,234	$ 564,892

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.

Departmental Allocation of Accumulated Provision
For Depreciation, Common Utility Plant Made on
a Revenue Basis

Accumulated Provision for Depreciation, Page 201, line 14		$ 564,892
		============
Electric Department	60%	338,935
Gas Department	15%	84,734
Water Department	25%	141,223

		$ 564,892
		============

Note: The accumulated provision for depreciation referred to above is classified as depreciation on general plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Net Purchases-Day Ahead Market(Acct 555)	237,103,624	193,974,561	385,322,793	217,273,746
8	Net Sales-Day Ahead Market (Acct 447)	316,056	27,433	(38,035,445)	
9	Net Purchases-Real Time Market(Acct 555)	27,969,431	28,774,412	48,200,125	27,831,577
10	Net Sales-Real Time Market (Acct 555)	(8,606,688)	(8,400,693)	(18,886,479)	(22,946,404)
11	Access Charge	30,263	52,117	82,632	79,145
12	Ancillary Services	(672,247)	311,991	(969,589)	(1,024,319)
13	Cost Recovery	1,316,472	7,142,505	(2,642,618)	1,257,378
14	Day Ahead Energy-Congestion-Losses	(38,500,009)	(8,179,712)	(27,353,945)	(28,878,925)
15	Hour Ahead Scheduling Process-RT Settlmt	2,509,868	11,793,665	(31,470,957)	28,957,377
16	GMC	11,586,949	13,074,526	16,793,558	12,200,121
17	FERC Fees	1,179,135	1,287,438	1,721,066	1,074,752
18	Other	(7,149,892)	(458,541)	806,874	(1,798,336)
19					
20					
21					
22					
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42					
43					
44					
45					
46	TOTAL	227,082,962	239,399,702	333,568,015	234,026,112

Schedule Page: 397 Line No.: 1 Column: b

(1)Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements.
(2)Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 7 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 7 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 7 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 7 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 8 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 8 Column: c

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Schedule Page: 397 Line No.: 8 Column: d

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Schedule Page: 397 Line No.: 9 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 9 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 9 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 9 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 10 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 10 Column: c

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Schedule Page: 397 Line No.: 10 Column: d

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Schedule Page: 397 Line No.: 10 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 11 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 11 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 11 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 11 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 12 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 12 Column: c

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Schedule Page: 397 Line No.: 12 Column: d

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Schedule Page: 397 Line No.: 12 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 13 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 13 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 13 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements

Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 13 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 14 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 14 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 14 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 14 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 15 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 15 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 15 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 15 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 16 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 16 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 16 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are

SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 16 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 17 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 17 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 17 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 17 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 18 Column: b

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 18 Column: c

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 18 Column: d

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

Schedule Page: 397 Line No.: 18 Column: e

Amounts in columns (b,c,d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements. These charges are recorded to A/C 555, but are not included in line#7 and #9. Amount based on new MRTU charge code.

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		MWh			MWh	
2	Reactive Supply and Voltage		MW	4,316		MW	
3	Regulation and Frequency Response	2,022,401	MW	9,622,250	4,164,193	MW	-17,704,715
4	Energy Imbalance		MWh			MWh	
5	Operating Reserve - Spinning	2,087,988	MW	10,258,936	1,764,043	MW	-4,834,964
6	Operating Reserve - Supplement	1,924,980	MW	1,726,968	4,777,484	MW	-1,292,289
7	Other		MW	57,398		MW	1,035,032
8	Total (Lines 1 thru 7)	6,035,369		21,669,868	10,705,720		-22,796,936

Schedule Page: 398   Line No.: 1   Column: b

"Scheduling, System Control and Dispatch" will be 0. Energy schedules will be recorded seperately in accordance to FERC Order 668.

Schedule Page: 398   Line No.: 2   Column: b

"Reactive Supply and Voltage" includes Supplemental Reactive Power at the ISO, charge codes 1302.

Schedule Page: 398   Line No.: 3   Column: b

"Regulation and Frequency Response" includes the Regulation Up and Regulation Down at the ISO, charge codes 6500, 6524, 6570, 6594, 6596, 6600, 6624, 6670, 6694, 6696, 6090, 6750 and 6760. It also includes flexible ramping constraint (FRC) charge codes 7024, 7050, 7056, 7057 and 7058 and pay for performance charges codes 7251, 7256, 7261 and 7266.

Schedule Page: 398   Line No.: 4   Column: b

"Energy Imbalance" will be 0. Energy will be recorded seperately in accordance to FERC Order 668.

Schedule Page: 398   Line No.: 5   Column: b

"Operating Reserve - Spinning" includes Spinning Reserve at the ISO, charge codes 6100, 6124, 6170, 6194, 6196, 6710

Schedule Page: 398   Line No.: 6   Column: b

"Operating Reserve - Supplement" includes Non-Spinning Reserve at the ISO, charge code 6200, 6224, 6270, 6294, 6296 and 6720.

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

"Other" includes black start energy charge code 3101 and Grid Management Charge 4560 for Market Services, a charge required by CAISO to provide Ancillary Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: SOUTHERN CALIFORNIA EDISON COMPANY

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	13,433	20	1800	12,585			848		
2	February	13,564	12	1800	12,869			695		
3	March	15,207	27	1500	14,116			1,091		
4	Total for Quarter 1				39,570			2,634		
5	April	16,250	30	1600	14,621			1,629		
6	May	15,705	1	1600	14,695			1,010		
7	June	19,355	30	1500	18,501			854		
8	Total for Quarter 2				47,817			3,493		
9	July	19,655	31	1600	16,109			3,546		
10	August	22,463	28	1600	20,999			1,464		
11	September	23,080	8	1600	21,558			1,522		
12	Total for Quarter 3				58,666			6,532		
13	October	20,759	9	1600	19,191			1,568		
14	November	13,556	30	1800	12,522			1,034		
15	December	14,311	15	1900	13,106			1,205		
16	Total for Quarter 4				44,819			3,807		
17	Total Year to Date/Year				190,872			16,466		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	5,753,499
4	Nuclear	5,102,974
5	Hydro-Conventional	919,122
6	Hydro-Pumped Storage	82,172
7	Other	305,069
8	Less Energy for Pumping	1,773
9	Net Generation (Enter Total of lines 3 through 8)	12,161,063
10	Purchases	70,487,195
11	Power Exchanges:	
12	Received	97,831
13	Delivered	332,792
14	Net Exchanges (Line 12 minus line 13)	-234,961
15	Transmission For Other (Wheeling)	
16	Received	6,219,728
17	Delivered	6,177,384
18	Net Transmission for Other (Line 16 minus line 17)	42,344
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	82,455,641

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	74,929,346
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,031,926
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	134,341
27	Total Energy Losses	3,360,028
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	82,455,641

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: SOUTHERN CALIFORNIA EDISON COMPANY

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	4,242,646	111,682	12,911	20	1900
30	February	1,972,289	203,768	13,167	12	1900
31	March	11,518,340	223,161	14,782	27	1700
32	April	3,819,831	210,227	15,836	30	1700
33	May	6,439,594	311,471	15,203	1	1700
34	June	6,826,947	199,537	19,070	30	1500
35	July	9,518,479	1,252,608	19,313	31	1700
36	August	8,922,147	227,602	22,064	28	1600
37	September	10,784,310	246,847	22,556	8	1600
38	October	6,577,684	346,968	20,404	9	1700
39	November	6,197,047	406,794	13,273	30	1900
40	December	5,636,327	291,261	14,050	15	1900
41	TOTAL	82,455,641	4,031,926			

Schedule Page: 401 Line No.: 22 Column: b

Excludes 11,418,267 Direct Access megawatt hours and 115,858 Customer Choice Aggregation megawatt hours.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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: *Palo Verde* (b)			Plant Name: *Mira Loma Peaker* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor			Outdoor		
3	Year Originally Constructed	1986			2007		
4	Year Last Unit was Installed	1988			2007		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	669.00			60.50		
6	Net Peak Demand on Plant - MW (60 minutes)	650			49		
7	Plant Hours Connected to Load	3901			8494		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	622			49		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	355			5		
12	Net Generation, Exclusive of Plant Use - KWh	5137323232			25550696		
13	Cost of Plant: Land and Land Rights	1935457			0		
14	Structures and Improvements	599061867			3260289		
15	Equipment Costs	1285556897			65307528		
16	Asset Retirement Costs	0			0		
17	Total Cost	1886554221			68567817		
18	Cost per KW of Installed Capacity (line 17/5) Including	2819.9615			1133.3523		
19	Production Expenses: Oper, Supv, & Engr	17059877			232273		
20	Fuel	36957101			702235		
21	Coolants and Water (Nuclear Plants Only)	6981608			0		
22	Steam Expenses	6459900			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	4549188			0		
26	Misc Steam (or Nuclear) Power Expenses	20367906			743383		
27	Rents	0			185		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	3553514			85137		
30	Maintenance of Structures	1049263			8384		
31	Maintenance of Boiler (or reactor) Plant	7848863			0		
32	Maintenance of Electric Plant	8837701			132177		
33	Maintenance of Misc Steam (or Nuclear) Plant	1787542			177857		
34	Total Production Expenses	115452463			2081631		
35	Expenses per Net KWh	0.0225			0.0815		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	NUCLEAR			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Grams of	Uranium		Gas-Mcf		
38	Quantity (Units) of Fuel Burned	0	791738	0	0	250793	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	66875151	0	0	1036	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	46.678	0.000	0.000	2.800	0.000
41	Average Cost of Fuel per Unit Burned	0.000	46.678	0.000	0.000	2.800	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.698	0.000	0.000	2.704	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.007	0.000	0.000	0.027	0.000
44	Average BTU per KWh Net Generation	0.000	10306.000	0.000	0.000	10166.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Grapeland Peaker* (b)			Plant Name: *McGrath Peaker* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	2007			2012		
4	Year Last Unit was Installed	2007			2012		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	60.50			60.50		
6	Net Peak Demand on Plant - MW (60 minutes)	49			49		
7	Plant Hours Connected to Load	8528			8603		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	49			49		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	5			5		
12	Net Generation, Exclusive of Plant Use - KWh	21636140			41581220		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	2905889			4030015		
15	Equipment Costs	68852641			95340560		
16	Asset Retirement Costs	0			0		
17	Total Cost	71758530			99370575		
18	Cost per KW of Installed Capacity (line 17/5) Including	1186.0914			1642.4888		
19	Production Expenses: Oper, Supv, & Engr	235159			232273		
20	Fuel	620285			1205259		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	878441			855577		
27	Rents	185			218		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	85327			119068		
30	Maintenance of Structures	8172			33432		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	243107			211956		
33	Maintenance of Misc Steam (or Nuclear) Plant	142911			203617		
34	Total Production Expenses	2213587			2861400		
35	Expenses per Net KWh	0.1023			0.0688		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Gas-Mcf			Gas-Mcf		
38	Quantity (Units) of Fuel Burned	0	210265	0	395858	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1038	0	1042	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	2.950	0.000	3.045	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	2.950	0.000	3.045	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	2.843	0.000	2.923	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.029	0.000	0.029	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10083.000	0.000	9917.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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: *Mountainview 3 & 4* (d)			Plant Name: *Barre Peaker* (e)			Plant Name: *Center Peaker* (f)			Line No.
Gas Turbine			Gas Turbine			Gas Turbine			1
Outdoor			Outdoor			Outdoor			2
2005			2007			2007			3
2006			2007			2007			4
1050.00			60.50			60.50			5
1050			49			49			6
8445			8547			8603			7
0			0			0			8
1050			49			49			9
0			0			0			10
35			5			5			11
5753498820			33129440			28754803			12
3218368			0			526947			13
50119008			2581713			2797238			14
700623117			74970839			76545747			15
0			0			0			16
753960493			77552552			79869932			17
718.0576			1281.8604			1320.1642			18
3233171			232273			232273			19
127519055			987337			830710			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
30467352			857590			828103			26
0			184			184			27
0			0			0			28
467814			85137			85137			29
404681			9482			8174			30
0			0			0			31
11236996			287818			250908			32
1718672			229569			139771			33
175047741			2689390			2375260			34
0.0304			0.0812			0.0826			35
GAS			GAS			GAS			36
Gas-Mcf			Gas-Mcf			Gas-Mcf			37
0	40635084	0	0	325373	0	0	280973	0	38
0	1027	0	0	1033	0	0	1033	0	39
0.000	3.138	0.000	0.000	3.034	0.000	0.000	2.957	0.000	40
0.000	3.138	0.000	0.000	3.034	0.000	0.000	2.957	0.000	41
0.000	3.054	0.000	0.000	2.938	0.000	0.000	2.863	0.000	42
0.000	0.022	0.000	0.000	0.030	0.000	0.000	0.029	0.000	43
0.000	7257.000	0.000	0.000	10143.000	0.000	0.000	10091.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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: *Offsite Storage* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Fuel Facilities			1
Storage/Pipelines			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	8	0	11
0	0	0	12
8555	0	0	13
722796	0	0	14
0	0	0	15
0	0	0	16
731351	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402   Line No.: -1   Column: b

Palo Verde: Data reported is on an SCE-share basis, which is consistent with nuclear industry practice.

Schedule Page: 402   Line No.: -1   Column: c

Mira Loma Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run constantly and is only on-line as the need requires.

Schedule Page: 403   Line No.: -1   Column: e

Barre Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run base-loaded and is on-line during peak hours as the need requires. Projected Annual Kw usage is 10% of total capacity during operational requirements.

Schedule Page: 403   Line No.: -1   Column: f

Center Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run base-loaded and is on-line during peak hours as the need requires. Projected Annual Kw usage is 10% of total capacity during operational requirements.

Schedule Page: 402   Line No.: 5   Column: b

Palo Verde: Data reported for Total Installed Capacity reported on a SCE-share basis. SCE is a 15.8% owner of Palo Verde 1, 2 and 3.

Schedule Page: 402   Line No.: 5   Column: c

Mira Loma Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 403   Line No.: 5   Column: e

Barre Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 403   Line No.: 5   Column: f

Center Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 402   Line No.: 9   Column: b

Palo Verde: Data reported for Total when not limited by Condenser Water reported on a SCE-share basis. SCE is a 15.8% owner of Palo Verde 1, 2 and 3.

Schedule Page: 402   Line No.: 10   Column: b

Palo Verde: Not Applicable.

Schedule Page: 402   Line No.: 10   Column: c

Mira Loma Peaker: Not applicable.

Schedule Page: 403   Line No.: 10   Column: d

Mountainview 3 & 4: Not applicable.

Schedule Page: 403   Line No.: 10   Column: e

Barre Peaker: Not Applicable.

Schedule Page: 403   Line No.: 10   Column: f

Center Peaker: Not Applicable.

Schedule Page: 402   Line No.: 11   Column: b

Palo Verde: Data reported for Total Average Number of Employees reported on a SCE share basis. SCE is a 15.8% owner of Palo Verde 1, 2, and 3.

Schedule Page: 402.1   Line No.: -1   Column: b

Grapeland Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run consistantly and only on-line during peak summer hours as the need requires. Projected annual Kw usage is 10% of total capacity during operational requirements.

Schedule Page: 402.1   Line No.: -1   Column: c

McGrath Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run constantly and is only on-line as the need requires.

Schedule Page: 403.1   Line No.: -1   Column: d

Offsite Storage Pipelines

Schedule Page: 402.1   Line No.: 5   Column: b

Grapeland Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 402.1 Line No.: 5 Column: c

McGrath Peaker*:* Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 402.1 Line No.: 10 Column: b

Grapeland Peaker: Not Applicable.

Schedule Page: 402.1 Line No.: 10 Column: c

McGrath Peaker*:* Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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. 2175 Plant Name: Big Creek No. 1 (b)	FERC Licensed Project No. 2175 Plant Name: Big Creek No. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1913	1913
4	Year Last Unit was Installed	1925	1925
5	Total installed cap (Gen name plate Rating in MW)	88.40	66.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	80	94
7	Plant Hours Connect to Load	2,616	2,663
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	88	99
10	(b) Under the Most Adverse Oper Conditions	88	99
11	Average Number of Employees	11	11
12	Net Generation, Exclusive of Plant Use - Kwh	52,329,103	51,790,376
13	Cost of Plant		
14	Land and Land Rights	0	1,344
15	Structures and Improvements	60,068,027	15,474,427
16	Reservoirs, Dams, and Waterways	5,425,680	5,389,503
17	Equipment Costs	37,179,050	28,108,090
18	Roads, Railroads, and Bridges	1,939,809	925,625
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	104,612,566	49,898,989
21	Cost per KW of Installed Capacity (line 20 / 5)	1,183.4001	750.3607
22	Production Expenses		
23	Operation Supervision and Engineering	454,226	294,057
24	Water for Power	183,409	138,050
25	Hydraulic Expenses	94,631	71,401
26	Electric Expenses	154,596	127,331
27	Misc Hydraulic Power Generation Expenses	900,079	579,110
28	Rents	46,926	35,321
29	Maintenance Supervision and Engineering	183,529	51,699
30	Maintenance of Structures	294,299	94,867
31	Maintenance of Reservoirs, Dams, and Waterways	94,570	77,662
32	Maintenance of Electric Plant	660,403	353,412
33	Maintenance of Misc Hydraulic Plant	134,635	94,413
34	Total Production Expenses (total 23 thru 33)	3,201,303	1,917,323
35	Expenses per net KWh	0.0612	0.0370

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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. 382 Plant Name: Borel (b)	FERC Licensed Project No. 67 Plant Name: Big Creek No. 2A (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1904	1928
4	Year Last Unit was Installed	1932	1928
5	Total installed cap (Gen name plate Rating in MW)	11.00	110.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	65
7	Plant Hours Connect to Load	0	2,884
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	11	67
10	(b) Under the Most Adverse Oper Conditions	11	67
11	Average Number of Employees	0	11
12	Net Generation, Exclusive of Plant Use - Kwh	-221,394	111,802,788
13	Cost of Plant		
14	Land and Land Rights	112,464	0
15	Structures and Improvements	578,842	2,597,980
16	Reservoirs, Dams, and Waterways	15,536,415	4,909,423
17	Equipment Costs	5,274,391	19,447,296
18	Roads, Railroads, and Bridges	25,609	13,269
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	21,527,721	26,967,968
21	Cost per KW of Installed Capacity (line 20 / 5)	1,957.0655	245.1633
22	Production Expenses		
23	Operation Supervision and Engineering	314,057	465,107
24	Water for Power	28,211	228,353
25	Hydraulic Expenses	41,478	119,337
26	Electric Expenses	16,003	133,293
27	Misc Hydraulic Power Generation Expenses	416,115	918,098
28	Rents	37,120	58,425
29	Maintenance Supervision and Engineering	20,656	85,518
30	Maintenance of Structures	2,843	12,405
31	Maintenance of Reservoirs, Dams, and Waterways	58,594	102,919
32	Maintenance of Electric Plant	13,302	161,318
33	Maintenance of Misc Hydraulic Plant	27,097	99,435
34	Total Production Expenses (total 23 thru 33)	975,476	2,384,208
35	Expenses per net KWh	0.0000	0.0213

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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. 2290 Plant Name: Kern River No. 3 (b)	FERC Licensed Project No. 2085 Plant Name: Mammoth Pool (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Outdoor
3	Year Originally Constructed	1921	1960
4	Year Last Unit was Installed	1921	1960
5	Total installed cap (Gen name plate Rating in MW)	36.50	190.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	17	179
7	Plant Hours Connect to Load	8,379	5,262
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	40	178
10	(b) Under the Most Adverse Oper Conditions	40	178
11	Average Number of Employees	18	10
12	Net Generation, Exclusive of Plant Use - Kwh	35,152,154	137,646,864
13	Cost of Plant		
14	Land and Land Rights	266,104	161,028
15	Structures and Improvements	2,163,559	2,469,432
16	Reservoirs, Dams, and Waterways	35,544,188	18,283,580
17	Equipment Costs	18,184,733	25,734,618
18	Roads, Railroads, and Bridges	3,506,970	525,860
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	59,665,554	47,174,518
21	Cost per KW of Installed Capacity (line 20 / 5)	1,634.6727	248.2869
22	Production Expenses		
23	Operation Supervision and Engineering	1,052,091	777,267
24	Water for Power	94,508	394,428
25	Hydraulic Expenses	126,933	209,842
26	Electric Expenses	239,781	227,244
27	Misc Hydraulic Power Generation Expenses	1,428,575	1,594,631
28	Rents	124,351	100,916
29	Maintenance Supervision and Engineering	69,197	147,712
30	Maintenance of Structures	97,990	10,983
31	Maintenance of Reservoirs, Dams, and Waterways	81,926	162,790
32	Maintenance of Electric Plant	95,061	19,976
33	Maintenance of Misc Hydraulic Plant	52,677	161,719
34	Total Production Expenses (total 23 thru 33)	3,463,090	3,807,508
35	Expenses per net KWh	0.0985	0.0277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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: Big Crk Wtr Col Fac (b)	FERC Licensed Project No. 0 Plant Name: All Facilities (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	3,543,903	0
15	Structures and Improvements	7,982,130	0
16	Reservoirs, Dams, and Waterways	106,533,845	0
17	Equipment Costs	2,292,180	0
18	Roads, Railroads, and Bridges	1,780,692	0
19	Asset Retirement Costs	0	903,871
20	TOTAL cost (Total of 14 thru 19)	122,132,750	903,871
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. 67 Plant Name: Big Creek No. 8 (d)	FERC Licensed Project No. 2174 Plant Name: Portal Power Plant (e)	FERC Licensed Project No. 1388 Plant Name: Poole Plant (f)	Line No.
Storage	Storage	Storage	1
Conventional	Conventional	Conventional	2
1921	1956	1924	3
1929	1956	1924	4
75.00	10.80	11.30	5
56	10	11	6
2,539	1,655	8,637	7
			8
71	11	11	9
71	11	11	10
10	11	0	11
42,164,923	9,696,118	17,636,634	12
			13
0	34,761	75,235	14
4,345,312	1,599,867	8,294,316	15
3,380,255	3,475,173	422,387	16
23,661,649	4,412,995	11,414,312	17
672,760	176,448	0	18
0	0	0	19
32,059,976	9,699,244	20,206,250	20
427.4663	898.0781	1,788.1637	21
			22
307,716	60,236	272,411	23
155,695	22,420	26,566	24
98,632	12,326	30,475	25
151,328	46,354	15,070	26
656,312	120,217	694,344	27
39,835	5,736	34,955	28
58,308	8,396	35,060	29
26,515	7,863	582	30
97,376	36,144	69,105	31
270,133	57,475	29,214	32
119,399	49,561	5,897	33
1,981,249	426,728	1,213,679	34
0.0470	0.0440	0.0688	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 120 Plant Name: Big Creek No. 3 (d)	FERC Licensed Project No. 2017 Plant Name: Big Creek No. 4 (e)	FERC Licensed Project No. 1930 Plant Name: Kern River No. 1 (f)	Line No.
Storage	Storage	Run-of-River	1
Conventional	Conventional	Conventional	2
1923	1951	1907	3
1980	1951	1907	4
181.90	100.00	26.50	5
170	97	24	6
6,027	3,915	8,156	7
			8
175	100	26	9
175	100	26	10
10	10	0	11
176,811,377	76,578,513	79,277,042	12
			13
6,142	104,451	120,432	14
8,707,345	2,508,434	6,994,099	15
20,258,913	16,202,201	36,145,326	16
51,724,103	14,784,421	17,059,302	17
1,745,414	136,631	1,532,742	18
0	0	0	19
82,441,917	33,736,138	61,851,901	20
453.2266	337.3614	2,334.0340	21
			22
798,568	480,227	688,309	23
362,147	207,594	62,036	24
186,852	109,170	84,253	25
365,690	137,047	135,432	26
1,574,468	846,968	1,000,749	27
92,657	53,114	81,354	28
135,623	77,743	45,270	29
83,090	9,007	26,025	30
206,136	125,529	251,159	31
656,446	14,946	120,809	32
274,138	104,357	64,597	33
4,735,815	2,165,702	2,559,993	34
0.0268	0.0283	0.0323	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: Poole Plant Res Fac (d)	FERC Licensed Project No. 1389 Plant Name: Rush Creek Res Fac (e)	FERC Licensed Project No. 1394 Plant Name: Bishop Plnt Res Fac (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
7,744	0	140,925	14
211,569	992,853	104,225	15
6,074,806	7,813,821	11,758,729	16
2,711,970	18,267	7,399,131	17
0	268,727	194,511	18
0	0	0	19
9,006,089	9,093,668	19,597,521	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
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Schedule Page: 406 Line No.: 1 Column: b

Big Creek No.1 Licensed Project No. 2175

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406 Line No.: 1 Column: c

Big Creek No.2 Licnesed Project No. 2175

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406 Line No.: 1 Column: d

Big Creek No. 8 Licensed Project No.67

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406 Line No.: 1 Column: e

Portal Poewr Plant Licensed Project No. 2174

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.1 Line No.: 1 Column: c

Big Creek No. 2A Licensed Project No. 67

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.1 Line No.: 1 Column: d

Big Creek No.3 Licensed Project No. 120

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.1 Line No.: 1 Column: e

Big Creek No.4 Licensed Project No. 2017

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.1 Line No.: 12 Column: b

Borel Licensed Project No. 382

There is no KWH generated during the plant year.

Schedule Page: 406.2 Line No.: 1 Column: c

Mammoth Pool Licensed Project No. 2085

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.2 Line No.: 2 Column: d

Pool Plant Res Fac

FERC Licensed Project Number 1388 - Pool Plant

Schedule Page: 406.2 Line No.: 20 Column: d

Pool Plant Res Fac

Operated by remote control from Pool Plant. Including Saddlebag, Tioga, and Rhinedollar reservoirs. Expenses incurred at

Pool Reservior Facilities are allocated to Pool Plant.

Schedule Page: 406.2 Line No.: 20 Column: e

Rush Creek Res Fac

Includes Rush Meadows Reservior, Gem Lake and Agnew Lake. Expenses incurred at Rush Creek Reservior Facilities are allocated to Rush Creek Plant.

Schedule Page: 406.2 Line No.: 20 Column: f

Bishop Plnt Res Fac

Includes Intake 2 Reservior, South Lake, Sabrina Lake, Birch and McGee Creek Diversions and miscellaneous Bishop creek water rights. Expenses incurrued at Bishop Plant Reservior Facilities are allocated at the end of tahe year to the Bisop Creek Plants.

Schedule Page: 406.3 Line No.: 20 Column: b

Big Crk Wtr Col Fac

Expenses incurred at Big Creek Water Collecting Facilities are allocated at the end of the year to the Big Creek Plants, which operate under the same federal licenses.
These include Huntington Lake (Reservior), Shaver Lake (Reservior), Florence Lake, Lake Thomas A. Edison, Mammoth Pool Lake and miscellenous Big Creek water rights, which are operated under licenses from the Federal Energy Regulatory Commission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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. 67 Plant Name: Eastwood (b)
1	Type of Plant Construction (Conventional or Outdoor)	Conventional
2	Year Originally Constructed	1987
3	Year Last Unit was Installed	1987
4	Total installed cap (Gen name plate Rating in MW)	200
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	204
6	Plant Hours Connect to Load While Generating	1,802
7	Net Plant Capability (in megawatts)	200
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	82,171,509
10	Energy Used for Pumping	-1,773,450
11	Net Output for Load (line 9 - line 10) - Kwh	83,944,959
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	50,418,322
15	Reservoirs, Dams, and Waterways	160,000,671
16	Water Wheels, Turbines, and Generators	31,458,434
17	Accessory Electric Equipment	16,010,132
18	Miscellaneous Powerplant Equipment	5,611,036
19	Roads, Railroads, and Bridges	2,687,590
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	266,186,185
22	Cost per KW of installed cap (line 21 / 4)	1,330.9309
23	Production Expenses	
24	Operation Supervision and Engineering	838,607
25	Water for Power	415,096
26	Pumped Storage Expenses	216,498
27	Electric Expenses	248,913
28	Misc Pumped Storage Power generation Expenses	1,612,936
29	Rents	106,121
30	Maintenance Supervision and Engineering	155,331
31	Maintenance of Structures	32,279
32	Maintenance of Reservoirs, Dams, and Waterways	163,380
33	Maintenance of Electric Plant	199,856
34	Maintenance of Misc Pumped Storage Plant	253,111
35	Production Exp Before Pumping Exp (24 thru 34)	4,242,128
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	4,242,128
38	Expenses per KWh (line 37 / 9)	0.0516

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
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			9
			10
			11
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			20
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			34
			35
			36
			37
			38

Schedule Page: 408   Line No.: 1   Column: b

All Big Creek Powerhouses are operated by remote control from Big Creek Dispatch Center located in the twon of Big Creek.

Entire Plant is underground in a cavern.

Schedule Page: 408   Line No.: 3   Column: b

Generation Equipment installed in 1987; Pumpback Equipment installed in 1990.

Schedule Page: 408   Line No.: 38   Column: b

Line 38 Column b -
Based on FERC guidance, a new line 39 is needed. Line 39 - Expense per KWh of Generation and Pumping (Line 37/(Line 9 + Line 10) and the value should be $0.05276 ($4,242,128 / 80,398,059 KWh).

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	Other Production					
2	Santa Catalina Island					
3	Unit 7 Diesel	1958	1.00			
4	Unit 8 Diesel	1963	1.50			
5	Unit 10 Diesel	1966	1.10			
6	Unit 12 Diesel	1976	1.60			
7	Unit 14 Diesel	1986	1.40			
8	Unit 15 Diesel	1995	2.80			
9	Micro-Turbines	2011	1.50			
10	TOTAL		10.90	5.1	29,101,646	66,245,902
11						
12						
13	Hydro					
14	Kaweah No.1	1929	2.30	2.0	6,519,993	23,007,421
15	Kaweah No.2	1929	1.80	2.0	6,422,720	9,176,375
16	Kaweah No.3	1913	4.80	4.8	12,261,787	11,237,084
17	Santa Ana No.1 & 2	1899	3.20	3.0	1,131,634	5,336,070
18	Santa Ana No.3	1999	3.10	3.0	2,974,922	26,021,699
19	Lower Tule	1909	2.50	3.0	5,918,789	38,001,567
20	Mill Creek No.1	1893	0.80	1.0	1,585,193	2,244,218
21	Mill Creek No. 2 & 3	1903	3.30	3.0	4,965,650	1,448,226
22	Lytle Creek	1904	0.50	1.0	618,883	1,284,537
23	Fontana	1917	3.00	2.0	1,627,364	693,768
24	Sierra	1922	0.50	1.0	592,952	800,007
25	Ontario No.1	1902	0.60	1.0	1,223,706	5,514,445
26	Ontario No.2	1963	0.30		308,046	1,441,596
27	Bishop Creek No. 2	1908	7.30	7.3	12,553,803	12,733,655
28	Bishop Creek No. 3	1913	7.80	7.8	12,682,787	8,454,912
29	Bishop Creek No. 4	1905	8.00	8.0	23,840,522	13,980,047
30	Bishop Creek No. 5	1919	4.50	4.0	4,970,828	5,981,591
31	Bishop Creek No. 6	1913	1.60	1.6	5,926,019	4,699,560
32	Rush Creek	1916	13.00	12.0	18,047,019	18,002,755
33	San Gorgonio No. 1 & 2	1923	2.40	2.0		7,010,795
34	Lundy	1911	3.00	3.0	4,284,872	6,436,610
35						
36						
37						
38	Other:					
39	Solar Photovoltaic					
40	SC-CHINO-SOL	2009	1.00	1.0	702,773	6,902,728
41	SC-RIALTO3-SOL	2010	1.00	1.0	1,255,487	8,296,636
42	SC-REDLND5-SOL	2010	2.50	2.5	4,371,075	28,067,157
43	SC-ONTAR6-SOL	2011	2.00	2.0	4,076,845	20,422,669
44	SC-REDLND7-SOL	2010	2.50	2.5	4,470,806	26,899,377
45	SC-ONTAR8-SOL	2010	2.00	2.0	3,964,426	23,425,419
46	SC-ONTAR9-SOL	2011	1.00	1.0	1,759,729	11,874,572

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	SC-ETWIND10-SOL	2011	1.50	1.5	2,699,012	18,505,577
2	SC-REDLND11-SOL	2011	3.50	3.5	6,460,750	41,246,779
3	SC-ONTAR12-SOL	2010	0.50	0.5	761,978	6,616,108
4	SC-REDLND13-SOL	2011	3.50	3.5	6,650,752	39,187,274
5	SC-ETWIND15-SOL	2011	3.50	3.5	5,029,975	20,040,056
6	SC-REDLND16-SOL	2011	1.50	1.5	2,528,101	17,051,714
7	SC-ETWIND17-SOL	2011	3.50	3.5	5,923,544	37,306,440
8	SC-ETWIND18-SOL	2011	1.50	1.5	2,344,571	17,323,396
9	SC-REDLND22-SOL	2010	2.00	2.0	3,408,824	12,202,470
10	SC-ETWIND23-SOL	2011	2.50	2.5	4,845,840	31,062,860
11	SC-ETWIND26-SOL	2011	6.00	6.0	10,790,146	70,752,446
12	SC-ETWIND27-SOL	2012	2.00	2.0	3,220,760	9,481,118
13	SC-VISTA28-SOL	2011	3.50	3.5	6,442,995	39,375,778
14	SC-ONTAR32-SOL	2011	1.50	1.5	2,467,888	13,518,096
15	SC-ONTAR33-SOL	2011	1.00	1.0	1,698,713	12,165,244
16	SC-VESTAL42-SOL	2010	5.00	5.0	9,284,961	45,765,844
17	SC-VALLY44-SOL	2012	8.00	8.0	13,799,915	65,653,925
18	SC-REDLND48-SOL	2013	5.00	5.0	8,992,206	19,550,591
19						
20	TOTAL SOLAR VOLTAIC				117,952,073	642,694,275
21						
22	Environmental Safety Services					
23	Demand Response and Grid Reliability					
24	UC Santa Barbara Fuel Cell	2012	0.20	0.2	1,449,513	
25	CS San Bernardino Fuel Cell	2013	1.40	1.4	5,913,604	
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46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
				Diesel		3
				Diesel		4
				Diesel		5
				Diesel		6
				Diesel		7
				Diesel		8
				Diesel		9
6,077,606	2,788,734	5,701,374	1,809,784		3,119	10
						11
						12
						13
10,003,227	337,301		229,166			14
5,097,986	267,490		185,887			15
2,341,059	614,073		177,489			16
1,667,522	427,025		230,901			17
8,394,096	392,274		183,262			18
15,200,627	356,503		216,139			19
2,805,273	132,150		34,974			20
438,856	399,976		79,641			21
2,569,074	106,166		28,515			22
231,256	377,267		72,391			23
1,600,014	108,277		54,723			24
9,190,742	120,280		23,162			25
4,805,320	73,728		56,246			26
1,744,336	883,574		85,703			27
1,083,963	737,268		176,741			28
1,747,506	756,075		213,736			29
1,329,242	435,748		67,283			30
2,937,225	169,201		36,325			31
1,384,827	1,249,549		315,221			32
2,921,165	65,944		25,866			33
2,145,537	383,134		51,433			34
						35
						36
						37
						38
						39
6,902,728	85,420		15,368			40
8,296,636	55,811		12,121			41
11,226,863	117,924		27,398			42
10,211,335	93,630		25,881			43
10,759,751	116,805		31,736			44
11,712,710	94,997		23,580			45
11,874,572	49,149		10,554			46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
12,337,051	72,128		17,554			1
11,784,794	166,354		45,245			2
13,232,217	24,694		7,424			3
11,196,364	164,323		41,871			4
5,725,730	138,400		45,772			5
11,367,809	74,476		16,522			6
10,658,983	175,995		37,771			7
11,548,931	70,510		21,083			8
6,101,235	96,705		19,683			9
12,425,144	120,697		30,219			10
11,792,074	284,032		75,483			11
4,740,559	111,093		23,804			12
11,250,222	165,669		42,617			13
9,012,064	78,185		17,320			14
12,165,244	54,239		13,212			15
9,153,169	218,151		52,882			16
8,206,741	388,303		102,253			17
3,910,118	252,246		64,289			18
						19
75,737,654	3,269,934		821,643			20
						21
	2,177,860					22
	2,200,077					23
	61,243	43,694	3,522			24
	18,484	243,746	451,455			25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Schedule Page: 410   Line No.: 17   Column: a

Licensed Projects:
Santa Ana #1 Project No. 1933. Santa Ana #2 decommissioned in 1998

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 18   Column: a

Licensed Projects:
Santa Ana #3 Project No. 1933

SCE owns and operates 5 non-licensed powerhouses: Mill Creek, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 19   Column: a

Licensed Projects:
Lower Tule Project No. 372

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 21   Column: a

Licensed Projects:
Mill Creek # 2 & 3 Project No. 1934. Mill Creek 2 is in the process of decommissioning.

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 22   Column: a

Licensed Projects:
Lytle Creek Project No. 1932

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 27   Column: a

Licensed Project:
Bishop Creek # 2 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 28   Column: a

Licensed Project:
Bishop Creek # 3 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 29   Column: a

Licensed Project:
Bishop Creek # 4 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410   Line No.: 30   Column: a

Licensed Project:
Bishop Creek # 5 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 31 Column: a

Licensed Project:
Bishop Creek #6 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 32 Column: a

Licensed Project:
Rush Creek Project No. 1389

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 33 Column: a

Licensed Project:
San Gorgonio # 1 & 2 Project No. 344

Hydro Plants San Gorgonio 1 & 2 are in the process of being decommissioned.

Schedule Page: 410 Line No.: 34 Column: a

Licensed Project:
Lundy Project No. 1390

SCE owns and operates 5 non-licensed powerhouses; Mill Creek1, Ontario 1, Ontario2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410.1 Line No.: 20 Column: a

Solar sites do not have a reliable way to measure plant use.

All Solar sites are commercially certified by CAISO.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	800 KV Lines							
2								
3	Sylmar	Celilo (CA)	800.00	800.00	Steel Tower	168.09		2
4	Sylmar	Celilo (NV)	800.00	800.00	Steel Tower	144.86		1
5								
6	500 KV Lines							
7								
8	Midway	Vincent #1 &2	500.00	500.00	Steel Tower	225.49		2
9	Lugo	Vincent #1 & #2	500.00	500.00	Steel Tower	94.39		2
10	Lugo	Mohave (NV)	500.00	500.00	Steel Tower	9.85		1
11	El Dorado	Lugo (CA)	500.00	500.00	Steel Tower	150.67		1
12	El Dorado	Lugo (NV)	500.00	500.00	Steel Tower	26.51		1
13	Lugo	Mira Loma #1-3	500.00	500.00	Steel Tower	83.09	13.41	3
14	Lugo	Mohave (CA)	500.00	500.00	Steel Tower	165.96		1
15	El Dorado	Mohave (NV)(c)	500.00	500.00	Steel Tower	19.93		1
16	El Dorado	Border (NV)	500.00	500.00	Steel Tower	29.65		1
17	Mira Loma	Serrano	500.00	500.00	Steel Tower	26.98	1.77	2
18	Lugo	Victorville	500.00	500.00	Steel Tower	7.57		1
19	Midway	Vincent #3	500.00	500.00	Steel Tower	52.62		1
20	Devers	Palo Verde (CA)	500.00	500.00	Steel Tower	126.45		1
21	Devers	Palo Verde (AZ)	500.00	500.00	Steel Tower	112.05		1
22	Devers	Valley	500.00	500.00	Steel Tower	41.60		1
23	Serrano	Valley	500.00	500.00	Steel Tower	40.52		1
24								
25	220 KV Lines							
26								
27	Pardee	Sylmar #1 & #2	220.00	220.00	Steel Tower	6.53	6.47	2
28	Eagle Rock	Sylmar	220.00	220.00	Steel Tower	0.04	1.75	1
29	Pardee	Vincent #4	220.00	220.00	Steel Tower	7.35		2
30	Pardee	Vincent #2	220.00	220.00	Steel Tower	2.74		1
31	Rio Hondo	Vincent #2	220.00	220.00	Steel Tower	4.42		1
32	Pardee	Various	220.00	220.00	Steel Tower	319.41	34.87	20
33	Cogen/Renew. Energy	Various	220.00	220.00	Steel Tower	3.57	4.85	6
34	Devers	Various	220.00	220.00	Steel Tower	127.00	16.69	10
35	Antelope	Various	220.00	220.00	Steel Tower	255.30	15.49	10
36					TOTAL	9,916.41	2,395.58	1,183

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Chino	Various	220.00	220.00	Steel Tower	85.39	83.81	5
2	Coachella Valley	Devers	220.00	220.00	Steel Tower	0.10	0.28	1
3	Big Creek #3	Big Creek #4	220.00	220.00	Steel Tower	5.79		1
4	Big Creek #3	Springville	220.00	220.00	Steel Tower	128.32		2
5	Laguna Bell	Various	220.00	220.00	Steel Tower	89.57	39.98	13
6	Hinson	Various	220.00	220.00	Steel Tower	15.30	11.77	4
7	El Nido	Various	220.00	220.00	Steel Tower	57.52	33.89	13
8	Pisgah #1-2	Various	220.00	220.00	Steel Tower	305.18		5
9	Mira Loma	Various	220.00	220.00	Steel Tower	89.75	66.00	16
10	Center	Various	220.00	220.00	Steel Tower	83.57	54.08	9
11	Alamitos	Various	220.00	220.00	Steel Tower	84.63	40.04	14
12	Big Creek #4	Magunden	220.00	220.00	Steel Tower	135.41		2
13	Moorpark	Various	220.00	220.00	Steel Tower	221.67	193.08	15
14	Cima	Pisgah (NV)	220.00	220.00	Steel Tower	84.46	0.63	4
15	Kramer	Various	220.00	220.00	Steel Tower	153.63	101.99	6
16	El Dorado	Meade (NV) (D)	220.00	220.00	Steel Tower	16.76		2
17	Pardee	Vincent #2	220.00	220.00	Steel Tower	27.48		1
18	Pearblossom	Vincent	220.00	220.00	Wood-H Frame	13.13		1
19	Ellis	Santiago #1 & #2	220.00	220.00	Steel Tower	14.93	14.56	3
20	Rio Hondo	Vincent #2	220.00	220.00	Steel Tower	20.57		1
21	Big Creek #2-3	Big Creek #8	220.00	220.00	Steel Tower	9.03		2
22	Big Creek #3	Mammoth Pool	220.00	220.00	Steel Tower	6.50		1
23	Big Creek	Various	220.00	220.00	Steel Tower	290.35	7.27	9
24	Serrano	Villa Park #1-3	220.00	220.00	Steel Tower	3.39	3.11	2
25	Big Creek #1	Eastwood	220.00	220.00	Steel Tower	4.66		1
26	Caldwell	Victor	220.00	220.00	Steel Tower	7.61		1
27	Devers	Various	220.00	220.00	Steel Tower	80.58	39.72	3
28								
29								
30	161 KV Lines							
31								
32	Blythe	Eagle Mountain	161.00	161.00	Wood H Frame	52.92	0.10	1
33								
34	115 KV Lines							
35			115.00	115.00	Steel Pole	147.15	84.22	
36					TOTAL	9,916.41	2,395.58	1,183

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1			115.00	115.00	Steel Tower	418.18	157.05	
2			115.00	115.00	Wood H Frame	391.09	10.44	
3			115.00	115.00	Wood Pole	615.47	41.30	
4			115.00	115.00	Underground	8.56	5.24	
5			66.00	115.00	Steel Pole	0.33		
6			66.00	115.00	Steel Tower	5.04	0.02	
7			66.00	115.00	Wood H Frame	0.82		
8			66.00	115.00	Wood Pole	4.89	0.09	
9			55.00	115.00	Steel Tower	1.41		
10			55.00	115.00	Wood Pole	0.47		
11		Total 115 KV Lines						133
12								
13	66 KV Lines							
14			66.00	66.00	Steel Pole	373.31	152.11	
15			66.00	66.00	Wood Pole	2,552.68	559.56	
16			66.00	66.00	Steel Tower	611.68	403.76	
17			66.00	66.00	Wood H Frame	126.05	31.82	
18			66.00	66.00	Underground	187.74	148.89	
19			66.00	66.00	Wood A Frame	0.38		
20		Total 66KV Lines						818
21								
22	55 KV Lines							
23			55.00	55.00	Steel Pole	0.66		
24			55.00	55.00	Steel Tower			
25			55.00	55.00	Wood H Frame	2.79		
26			55.00	55.00	Wood Pole	92.62	0.89	
27		Total 55 KV Lines						8
28								
29	33 KV Lines							
30			33.00	33.00	Steel Tower	8.53		
31			33.00	33.00	Underground	1.52	0.28	
32			33.00	33.00	Wood Pole	18.45	13.28	
33			33.00	33.00	Steel Pole	5.42	0.76	
34			33.00	33.00	Wood H Frame	0.33	0.26	
35		Total 33 KV Lines						9
36					TOTAL	9,916.41	2,395.58	1,183

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1								
2								
3								
4	33 & 66 KV Lines							
5		Total 33 & 66 KV Lines						
6								
7	Miscellaneous Adjustments							
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	9,916.41	2,395.58	1,183

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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
								2
	136,841	43,995,027	44,131,868					3
	668,871	13,330,576	13,999,447					4
								5
								6
								7
	3,706,358	43,901,203	47,607,561	56,243	156,835		213,078	8
	1,751,357	15,558,393	17,309,750	4,665	83,369		88,034	9
	177,040	1,989,137	2,166,177					10
	1,448,120	27,778,980	29,227,100	466			466	11
	36,677	6,442,413	6,479,090	2,747	60		2,807	12
	10,183,519	45,604,959	55,788,478	26,802	229,942	2,700	259,444	13
	607,445	26,033,347	26,640,792		350,849		350,849	14
	132,115	4,109,597	4,241,712	6,167	475,284		481,451	15
	151,231	4,693,851	4,845,082	1,612	204,858		206,470	16
	1,948,874	28,057,506	30,006,380	28,053	1,422,447	22,487	1,472,987	17
	748,912	2,292,131	3,041,043	2,924	89,950		92,874	18
	6,016,150	28,215,457	34,231,607	89,537	984,405	88,922	1,162,864	19
	15,243,707	423,875,836	439,119,543		2,252		2,252	20
	1,340,955	45,869,950	47,210,905	6,126	77,753	352,236	436,115	21
	26,409,426	268,717,237	295,126,663	186,802	1,048,276	106,585	1,341,663	22
	5,495,635	38,707,529	44,203,164	19,563	737,699		757,262	23
								24
								25
								26
	225,218	1,175,663	1,400,881	61,668	1,055,773	161,945	1,279,386	27
	186,657	276,517	463,174	3,211	122,625	1,858,580	1,984,416	28
	145,317	521,234	666,551					29
	33,954	1,169,080	1,203,034					30
	72,932	576,910	649,842					31
	2,601,693	55,216,841	57,818,534	18,496	830,110		848,606	32
	1,466,128	7,904,007	9,370,135	5,693	258,245	112,116	376,054	33
	4,034,874	62,111,034	66,145,908	7,498	56,726		64,224	34
	82,741,114	203,516,750	286,257,864	29,271	214,891	101	244,263	35
	327,216,957	3,538,723,052	3,865,940,009	3,515,146	28,822,074	7,995,130	40,332,350	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
	8,522,121	32,853,711	41,375,832	272,843	2,373,187	6,915	2,652,945	1
								2
	31,372	418,220	449,592	11,662	10,187		21,849	3
	1,424,549	4,569,157	5,993,706	88,415	570,945	18,037	677,397	4
	3,514,705	24,556,982	28,071,687	9,559	13,713	1,531	24,803	5
	1,634,441	6,758,309	8,392,750	310,170	2,710,343	2,197,493	5,218,006	6
	3,608,110	21,798,813	25,406,923	13,108	15,068	27,965	56,141	7
	1,156,399	8,535,802	9,692,201	22,532	278,220	17,533	318,285	8
	5,792,326	33,626,483	39,418,809	600,347	3,259,854	855,399	4,715,600	9
	2,972,925	38,824,630	41,797,555	19,176	509,106		528,282	10
	4,303,370	16,851,707	21,155,077	7,732	413,031		420,763	11
	425,481	4,260,104	4,685,585	2,222	97,225		99,447	12
	13,259,439	47,947,964	61,207,403					13
	25,048	1,197,458	1,222,506					14
	2,332,963	19,340,934	21,673,897	762,401	3,203,698	27,708	3,993,807	15
	11,017	1,261,083	1,272,100	12,111	39,006	644,248	695,365	16
	4,029,224	8,070,532	12,099,756		-4,049		-4,049	17
	332,719	1,198,247	1,530,966	4,616	276,345	71,505	352,466	18
	12,058,070	11,710,845	23,768,915	9,633	85,401		95,034	19
	15,882,266	323,934,340	339,816,606					20
		300,481	300,481	1,309	23,086		24,395	21
	42,221	788,996	831,217	9,855	37,907	6,251	54,013	22
	11,833,630	45,593,021	57,426,651	5,384	96,120		101,504	23
	78,248	2,918,602	2,996,850	97,839	877,692		975,531	24
		6,678,804	6,678,804	9,096	4,694		13,790	25
								26
	1,198,858	12,131,574	13,330,432					27
								28
								29
								30
								31
	38,155	2,372,268	2,410,423	3,050	13,054		16,104	32
								33
								34
								35
	327,216,957	3,538,723,052	3,865,940,009	3,515,146	28,822,074	7,995,130	40,332,350	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)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
	17,720,536	254,851,297	272,571,833	28,294	345,472	1,354	375,120	11
								12
								13
								14
								15
								16
								17
								18
								19
	47,265,734	1,202,912,202	1,250,177,936	560,917	3,007,257	28,609	3,596,783	20
								21
								22
								23
								24
								25
								26
	10,585	732,206	742,791	29,414	1,071,382	6,675	1,107,471	27
								28
								29
								30
								31
								32
								33
								34
	1,325	87,115	88,440					35
	327,216,957	3,538,723,052	3,865,940,009	3,515,146	28,822,074	7,995,130	40,332,350	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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
								2
								3
								4
				65,917	1,091,781	1,378,235	2,535,933	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
	327,216,957	3,538,723,052	3,865,940,009	3,515,146	28,822,074	7,995,130	40,332,350	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Construction					
2	LAKEVIEW	MOVAL VALLEY-LAKEVIEW	1.45	OH	22.00	1	1
3	LAKEVIEW	MOVAL VALLEY-LAKEVIEW	1.70	OH	22.00	1	1
4							
5							
6							
7							
8							
9							
10							
11							
12	Underground	Construction					
13	BARRE	KINDER-LAMPSON	0.20	UG		1	1
14	ISLA VISTA	ONSHORE	0.05	UG		1	1
15	SANTA CLARA	SAN MIGUEL	0.93	UG		1	1
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	TOTAL		4.33		44.00	5	5

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
654	ACSR	STP	115		1,176,812	106,174		1,282,986	2
654	ACSR	STP	115		1,379,807	140,570		1,520,377	3
									4
									5
									6
									7
									8
									9
									10
									11
									12
3000	KCM CU	UG	66		125,636	446,696		572,332	13
1750	XLP	UG	66			196,120		196,120	14
3000	KCM CU	UG	66		257,136	2,821,733		3,078,869	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
					2,939,391	3,711,293		6,650,684	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	ANTELOPE-LANCASTER	TU	500.00	220.00	13.80
2	ANTELOPE-LANCASTER	TU	220.00	66.00	
3	BAILEY-LANCASTER	TU	220.00	66.00	
4	BARRE-FULLERTON	TU	220.00	66.00	
5	BARRE-FULLERTON	TU	66.00	12.00	
6	CAMINO-TWENTY-NINE	TU	220.00	16.00	
7	CENTER-WHITTIER	TU	220.00	66.00	
8	CENTER-WHITTIER	TU	72.00	12.00	
9	CENTER-WHITTIER	TU	66.00	12.00	
10	CHEVMAIN-EL SEGUNDO	TU	220.00	66.00	
11	CHEVMAIN-EL SEGUNDO	TU	66.00	16.00	
12	CHEVMAIN-EL SEGUNDO	TU	66.00	13.20	
13	CHINO-ONTARIO	TU	220.00	66.00	
14	CHINO-ONTARIO	TU	72.00	12.00	
15	CHINO-ONTARIO	TU	66.00	12.00	
16	CIMA-HI DESERT	TU	220.00	16.00	
17	COLORADO RIVER-BLYTHE	TU	500.00	220.00	13.80
18	DEL AMO-LONG BEACH	TU	230.00	66.00	
19	DEL AMO-LONG BEACH	TU	220.00	66.00	
20	DEL AMO-LONG BEACH	TU	66.00	12.00	
21	DEVERS-PALM SPRINGS	TA	500.00	220.00	
22	DEVERS-PALM SPRINGS	TA	220.00	115.00	13.80
23	DEVERS-PALM SPRINGS	TA	115.00	12.00	
24	DEVERS-PALM SPRINGS	TA	66.00	12.00	
25	EAGLE MOUNTAIN-BLYTHE	TU	220.00	161.00	12.00
26	EAGLE MOUNTAIN-BLYTHE	TU	220.00	161.00	72.00
27	EAGLE MOUNTAIN-BLYTHE	TU	220.00	66.00	
28	EAGLE MOUNTAIN-BLYTHE	TU	66.00	12.00	
29	EAGLE ROCK-MONROVIA	TU	220.00	66.00	
30	EL CASCO-CALIMESA	TU	220.00	115.00	
31	EL CASCO-CALIMESA	TU	115.00	12.00	
32	EL NIDO-INGLEWOOD	TA	220.00	66.00	
33	EL NIDO-INGLEWOOD	TA	66.00	16.00	
34	ELDORADO-CLARK CO., N	TA	500.00	220.00	13.80
35	ELLIS-HUNTINGTON BEACH	TU	220.00	66.00	
36	ELLIS-HUNTINGTON BEACH	TU	66.00	12.00	
37	GOLETA-SANTA BARBARA	TU	220.00	66.00	
38	GOLETA-SANTA BARBARA	TU	66.00	16.00	
39	GOLETA-SANTA BARBARA	TU	66.00	12.00	
40	GOULD-MONROVIA	TU	220.00	66.00	

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	GOULD-MONROVIA	TU	66.00	16.00	
2	GOULD-MONROVIA	TU	33.00	16.00	
3	HINSON-LONG BEACH	TU	220.00	66.00	
4	IVANPAH-NIPTON	DU	220.00	115.00	
5	JOHANNA-SANTA ANA	TU	220.00	66.00	
6	JOHANNA-SANTA ANA	TU	66.00	12.00	
7	KRAMER-RIDGECREST	TU	230.00	115.00	
8	KRAMER-RIDGECREST	TU	115.00	33.00	
9	KRAMER-RIDGECREST	TU	33.00	2.40	
10	LA CIENEGA-SANTA MONICA	TU	220.00	66.00	
11	LA FRESA-REDONDO	TU	220.00	66.00	
12	LA FRESA-REDONDO	TU	66.00	16.00	
13	LAGUNA BELL-MONTEBELLO	TU	220.00	66.00	
14	LAGUNA BELL-MONTEBELLO	TU	66.00	16.00	
15	LIGHTHIPE-LONG BEACH	TA	220.00	66.00	
16	LIGHTHIPE-LONG BEACH	TA	66.00	12.00	
17	LUGO-HI DESERT	TA	500.00	220.00	
18	MESA-MONTEBELLO	TA	220.00	66.00	
19	MESA-MONTEBELLO	TA	69.00	12.00	
20	MESA-MONTEBELLO	TA	66.00	16.00	
21	MIRA LOMA-ONTARIO	TA	525.00	230.00	
22	MIRA LOMA-ONTARIO	TA	230.00	70.00	
23	MIRA LOMA-ONTARIO	TA	66.00	12.00	
24	MIRAGE-PALM SPRINGS	TU	220.00	115.00	
25	MOORPARK-THOUSAND OAK	TU	220.00	66.00	
26	MOORPARK-THOUSAND OAK	TU	66.00	16.00	
27	OLINDA-FULLERTON	TU	220.00	66.00	
28	OLINDA-FULLERTON	TU	66.00	12.00	
29	PADUA-FOOTHILL	TU	220.00	66.00	
30	PADUA-FOOTHILL	TU	66.00	12.00	
31	RANCHO VISTA-ETIWANDA	TU	500.00	220.00	13.80
32	RECTOR-VISALIA	TA	230.00	66.00	
33	RECTOR-VISALIA	TA	230.00	9.50	
34	RECTOR-VISALIA	TA	66.00	12.00	
35	RED BLUFF-VIDAL	TU	500.00	220.00	13.80
36	RIO HONDO-MONROVIA	TU	230.00	66.00	
37	RIO HONDO-MONROVIA	TU	220.00	66.00	
38	RIO HONDO-MONROVIA	TU	66.00	16.00	
39	RIO HONDO-MONROVIA	TU	66.00	12.00	
40	SANTA CLARA-VENTURA	TU	220.00	72.00	

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1	SANTA CLARA-VENTURA	TU	220.00	66.00	
2	SANTIAGO-EL TORO	TU	220.00	66.00	
3	SANTIAGO-EL TORO	TU	66.00	12.00	
4	SAUGUS-SAN FERNANDO	TU	220.00	66.00	
5	SAUGUS-SAN FERNANDO	TU	66.00	16.00	
6	SERRANO-ORANGE	TU	500.00	220.00	
7	SPRINGVILLE-PORTERVILLE	TU	220.00	66.00	
8	SPRINGVILLE-PORTERVILLE	TU	66.00	12.00	
9	VALLEY-SAN JACINTO	TA	525.00	120.00	
10	VALLEY-SAN JACINTO	TA	115.00	12.00	
11	VESTAL-DELANO	TU	220.00	66.00	
12	VESTAL-DELANO	TU	66.00	12.00	
13	VICTOR-HI DESERT	TU	220.00	115.00	
14	VICTOR-HI DESERT	TU	115.00	33.00	
15	VICTOR-HI DESERT	TU	115.00	12.00	
16	VICTOR-HI DESERT	TU	34.00	4.00	
17	VIEJO-LAKE FOREST	TU	220.00	66.00	
18	VIEJO-LAKE FOREST	TU	66.00	12.00	
19	VILLA PARK-SANTA ANA	TU	220.00	66.00	
20	VILLA PARK-SANTA ANA	TU	66.00	12.00	
21	VINCENT-LANCASTER	TA	500.00	220.00	
22	VISTA-INLAND	TA	220.00	115.00	
23	VISTA-INLAND	TA	220.00	66.00	
24	WALNUT-COVINA	TU	220.00	66.00	
25	WALNUT-COVINA	TU	66.00	12.00	
26	ALAMITOS-LONG BEACH	TU	220.00	66.00	
27	BIG CREEK 1-BIG CREEK	TU	230.00	13.10	
28	BIG CREEK 1-BIG CREEK	TU	230.00	7.20	
29	BIG CREEK 1-BIG CREEK	TU	34.00	14.40	
30	BIG CREEK 1-BIG CREEK	TU	33.00	7.90	
31	BIG CREEK 2-NR. BIG CREEK	TU	230.00	7.20	
32	BIG CREEK 2-NR. BIG CREEK	TU	220.00	13.80	
33	BIG CREEK 2-NR. BIG CREEK	TU	12.00	7.20	
34	BIG CREEK 3-NR. AUBERRY	TU	240.00	13.80	
35	BIG CREEK 3-NR. AUBERRY	TU	230.00	13.80	
36	BIG CREEK 4-NR. AUBERRY	TU	240.00	11.50	
37	BIG CREEK 4-NR. AUERRY	TU	12.00	0.24	
38	BIG CREEK 8-NR. BIG CREEK	TU	235.00	13.50	
39	BOREL-LAKE ISABELLA	TU	66.00	2.40	
40	BUCKWIND-NORTH PALM SPRINGS	TU	115.00	12.40	

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SUBSTATIONS

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1	CARBOGEN-LONG BEACH	TU	66.00	12.00	
2	CHARMIN-OXNARD	TU	66.00	12.00	
3	CHARMIN-OXNARD	TU	66.00	4.00	22.40
4	CHEVGEN-EL SEGUNDO	TU	66.00	13.80	
5	COOL WATER-DAGGETT	TU	115.00	13.20	
6	COOL WATER-DAGGETT	TU	115.00	4.16	12.40
7	CORNERS-LONG BEACH	TU	66.00	2.40	
8	CRYCO-INDUSTRY	TU	66.00	13.80	
9	DAIRYMANS-TULARE	TU	66.00	12.00	
10	EASTWOOD-SHAVER LAKE	TU	220.00	13.80	
11	ETIWANDA-ETIWANDA	TU	230.00	18.00	
12	ETIWANDA-ETIWANDA	TU	220.00	66.00	
13	ETIWANDA-ETIWANDA	TU	220.00	16.00	
14	ETIWANDA-ETIWANDA	TU	67.00	16.00	
15	ETIWANDA-ETIWANDA	TU	66.00	12.00	
16	ETIWANDA-ETIWANDA	TU	66.00	4.00	
17	FEDERALGEN-COMMERCE	TU	66.00	12.00	
18	HILLGEN-CITY OF INDUSTRY	TU	66.00	12.00	
19	HUNTINGTON BEACH-HUNTINGTON BEACH	TU	230.00	13.80	
20	HUNTINGTON BEACH-HUNTINGTON BEACH	TU	68.00	16.00	
21	KAWEAH 1-THREE RIVERS	TU	66.00	2.40	
22	KAWEAH 2-THREE RIVERS	TU	66.00	2.40	
23	KAWEAH 3-THREE RIVERS	TU	72.00	2.40	
24	KERN RIVER 1-KERN CANYON	TU	70.00	2.60	
25	KERN RIVER 1-KERN CANYON	TU	66.00	2.40	
26	KERN RIVER 3-KERNVILLE	TU	72.00	11.00	
27	KERN RIVER 3-KERNVILLE	TU	75.00	2.70	
28	LANPRI-LANCASTER	TU	66.00	12.00	
29	LUNDY-NR. LEE VINING	TU	55.00	16.00	
30	LUNDY-NR. LEE VINING	TU	55.00	2.40	
31	MAMMOTH-BIG CREEK	TU	220.00	12.00	
32	MAMMOTH POOL-BIG CREEK	TU	230.00	12.00	
33	MCGRATH BEACH-OXNARD	TU	66.00	13.00	
34	MIDWIND-LANCASTER	TU	66.00	12.00	
35	MILLCREEK 1-INLAND	TU	12.00	1.00	
36	MILLCREEK 2-INLAND	TU	12.00	1.00	
37	MOHAVE-LAUGHLIN, NE	TU	500.00	22.00	
38	ONTARIO POWERHOUSE-SAN ANTONIO CANYON	TU	12.00	2.40	
39	ORCOGEN-HUNTINGTON BEACH	TU	66.00	12.00	
40	ORMOND BEACH-OXNARD	TU	220.00	66.00	

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1	ORMOND BEACH-OXNARD	TU	133.00	25.30	
2	PEBBLY BEACH-AVALON	TU	12.00	2.40	
3	PEBBLY BEACH-AVALON	TU	12.00	2.40	
4	PITCHGEN-SAUGUS	TU	66.00	12.00	
5	POOLE-NR. LEE VINING	TU	7.00	122.00	
6	POOLE-NR. LEE VINING	TU	12.00	7.00	
7	PORTAL-BIG CREEK	TU	33.00	4.00	
8	PROCGEN-OXNARD	TU	66.00	12.00	
9	RENWIND-PALM SPRINGS	TU	115.00	12.40	
10	REPRO-EL SEGUNDO	TU	66.00	16.00	
11	RUSH CREEK-NR. JUNE LAKE	TU	115.00	2.40	
12	SAN BERNARDINO-INLAND	TU	220.00	66.00	
13	SAN BERNARDINO-INLAND	TU	66.00	12.00	
14	SAN ONOFRE-SAN ONOFRE	TA	220.00	12.00	
15	SANIGEN-WALNUT	TU	66.00	12.00	
16	SANTA ANA RIVER 1-FOOTHILL	TU	34.00	2.40	
17	SANTA ANA RIVER 3-FOOTHILL	TU	35.00	4.16	
18	SERRFGEN-LONG BEACH	TU	66.00	12.00	
19	SIGGEN-NORWALK	TU	66.00	12.00	
20	SIMPSON PAPER-POMONA	TU	66.00	12.00	
21	SKINWATER-WINCHESTER	TU	33.00	4.00	
22	SOUTHWIND-LANCASTER	TU	66.00	12.00	
23	TIMBERWINE-BIG CREEK	TU	33.00	12.00	
24	TULE-NR. SPRINGVILLE	TU	33.00	4.00	
25	VENWIND-PALM SPRINGS	TU	115.00	12.00	
26	WHIRLWIND-ROSAMOND	TU	500.00	220.00	13.80
27	WILLAMETTE-OXNARD	TU	66.00	12.00	
28	WINDHUB-TEHACAHPI	TU	500.00	220.00	13.80
29	WINDHUB-TEHACAHPI	TU	220.00	66.00	
30	ACTON-SAN JACINTO	DU	66.00	12.00	
31	AEROJET-AZUSA	DU	66.00	12.00	
32	AFG-HESPERIA	DU	115.00	12.00	
33	AIR PRODUCTS-CARSON	DU	66.00	16.00	
34	ALDER-FOOTHILL	DU	66.00	12.00	
35	ALESSANDRO-SAN JACINTO	DU	115.00	33.00	
36	ALESSANDRO-SAN JACINTO	DU	115.00	12.00	
37	ALHAMBRA-MONTEBELLO	DU	66.00	16.00	
38	ALHAMBRA-MONTEBELLO	DU	66.00	4.00	
39	ALLEN-MONROVIA	DU	16.00	4.00	
40	ALON-COMPTON	DU	66.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	AMADOR-EL MONTE	DU	66.00	16.00	
2	AMADOR-EL MONTE	DU	66.00	4.00	
3	AMALIA-MONTEBELLO	DU	16.00	4.00	
4	AMARGO-RIDGECREST	DU	33.00	4.00	
5	AMBOY-TWENTY-NINE PALMS	DU	33.00	12.00	
6	AMCO-TORRANCE	DU	66.00	12.00	
7	AMCO-TORRANCE	DU	12.00	4.00	
8	AMERON-ETIWANDA	DU	66.00	33.00	
9	ANAVERDE-LANCASTER	DU	66.00	12.00	
10	ANITA-MONROVIA	DU	66.00	16.00	
11	ANITA-MONROVIA	DU	66.00	4.00	
12	APL-LONG BEACH	DU	66.00	4.00	
13	APOLLO-HUNTINGTON BEACH	DU	66.00	12.00	
14	APPLE VALLEY-HI DESERT	DU	115.00	12.00	
15	AQUEDUCT-HI DESERT	DU	115.00	12.00	
16	ARCADIA-MONROVIA	DU	66.00	16.00	
17	ARCADIA-MONROVIA	DU	66.00	4.00	
18	ARCH BEACH-EL TORO	DU	12.00	4.00	
19	ARCHIBALD-FOOTHILL	DU	66.00	12.00	
20	ARCHLINE-ONTARIO	DU	66.00	12.00	
21	ARCO-LONG BEACH	DU	66.00	12.00	
22	ARRO-SAN BERNARDINO	DU	33.00	4.00	
23	ARROWHEAD-ARROWHEAD	DU	115.00	33.00	
24	ARROWHEAD-ARROWHEAD	DU	33.00	12.00	
25	ARROWHEAD-ARROWHEAD	DU	33.00	4.00	
26	ARROYO-GLENDORA	DU	66.00	16.00	
27	ARROYO-GLENDORA	DU	16.00	4.00	
28	ARTESIA-LONG BEACH	DU	12.00	4.00	
29	ASTRO-LONG BEACH	DU	66.00	12.00	
30	ATHENS-COMPTON	DU	16.00	4.00	
31	ATWOOD-FULLERTON	DU	66.00	12.00	
32	AULD-SAN JACINTO	DU	115.00	33.00	
33	AULD-SAN JACINTO	DU	115.00	12.00	
34	AZUSA-AZUSA	DU	66.00	12.00	
35	BADILLO-COVINA	DU	12.00	4.00	
36	BAIN-MIRA LOMA	DU	66.00	12.00	
37	BAKER-HI DESERT	DU	115.00	33.00	
38	BAKER-HI DESERT	DU	115.00	12.00	
39	BANDINI-COMPTON	DU	66.00	16.00	
40	BANNING-INLAND	DU	115.00	33.00	

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1	BARSTOW-HI DESERT	DU	33.00	12.00	
2	BARTOLO-WHITTIER	DU	12.00	4.00	
3	BASSETT-COVINA	DU	66.00	12.00	
4	BASTA-FULLERTON	DU	12.00	4.00	
5	BAYSIDE-HUNTINGTON BEACH	DU	66.00	12.00	
6	BEAUMONT-INLAND	DU	12.00	4.00	
7	BEDFORD-SANTA MONICA	DU	16.00	4.00	
8	BELDING-PALM SPRINGS	DU	33.00	4.00	
9	BELMONT-LONG BEACH	DU	12.00	4.00	
10	BELVEDERE-MONTEBELLO	DU	16.00	4.00	
11	BEVERLY-SANTA MONICA	DU	66.00	16.00	
12	BEVERLY-SANTA MONICA	DU	66.00	4.00	
13	BICKNELL-MONTEBELLO	DU	16.00	4.00	
14	BIXBY-LONG BEACH	DU	12.00	4.00	
15	BLACK MOUNTAIN-APPLE VALLEY	DU	115.00	4.00	
16	BLISS-TULARE	DU	66.00	12.00	
17	BLOOMINGTON-FOOTHILL	DU	66.00	12.00	
18	BLUFF COVE-REDONDO	DU	16.00	4.00	
19	BLYTHE-BLYTHE	DU	161.00	33.00	
20	BLYTHE CITY-BLYTHE	DU	33.00	12.00	
21	BLYTHE CITY-BLYTHE	DU	33.00	4.80	
22	BOLSA-HUNTINGTON BEACH	DU	66.00	12.00	
23	BOOST-LONG BEACH	DU	66.00	12.00	
24	BORREGO-EL TORO	DU	66.00	12.00	
25	BOTTLE-CABAZON	DU	115.00	4.00	
26	BOVINE-LONG BEACH	DU	66.00	12.00	
27	BOWL-LONG BEACH	DU	66.00	12.00	
28	BOWL-LONG BEACH	DU	66.00	4.00	
29	BOXWOOD-PORTERVILLE	DU	66.00	12.00	
30	BRADBURY-MONROVIA	DU	66.00	16.00	
31	BREA-FULLERTON	DU	66.00	12.00	
32	BREEZE-LANCASTER	DU	66.00	12.00	
33	BREW-IRWINDALE	DU	66.00	4.00	
34	BREWSTER-COMPTON	DU	16.00	4.00	
35	BRIDGE-REDONDO	DU	66.00	4.00	
36	BRIGHTON-REDONDO	DU	66.00	16.00	
37	BROADWAY-LONG BEACH	DU	66.00	12.00	
38	BROADWAY-LONG BEACH	DU	12.00	4.00	
39	BROOKHURST-HUNTINGTON BEACH	DU	66.00	12.00	
40	BROWNING-DELANO	DU	66.00	12.00	

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1	BRYAN-SANTA ANA	DU	66.00	12.00	
2	BRYMAN-HI DESERT	DU	33.00	4.00	
3	BULLIS-COMPTON	DU	66.00	16.00	
4	BULLIS-COMPTON	DU	66.00	4.00	
5	BUNKER-SAN JACITO	DU	115.00	12.00	
6	BURNT MILL-LAKE ARROWHEAD	DU	33.00	12.00	
7	BURPIT-ORANGE	DU	66.00	4.00	
8	BURRO FLATS-CHATSWORTH	DU	66.00	4.00	
9	CABAZON-PALM SPRINGS	DU	33.00	12.00	
10	CABRILLO-EL TORO	DU	66.00	12.00	
11	CADY-HI DESERT	DU	33.00	12.00	
12	CAJALCO-PERRIS	DU	115.00	12.00	
13	CAL CEMENT-MOJAVE	DU	66.00	4.00	
14	CALCITY-CAL CITY	DU	33.00	12.00	
15	CALDEN-COMPTON	DU	66.00	16.00	
16	CALECTRIC-INLAND	DU	115.00	33.00	
17	CALECTRIC-INLAND	DU	110.00	34.50	
18	CAMARILLO-VENTURA	DU	66.00	16.00	
19	CAMDEN-SANTA ANA	DU	66.00	12.00	
20	CAMERON-LONG BEACH	DU	66.00	12.00	
21	CANTIL-RIDGECREST	DU	33.00	12.00	
22	CANYON-FULLERTON	DU	66.00	12.00	
23	CANYON LAKE-SAN JACINTO	DU	33.00	12.00	
24	CAPITAN-SANTA BARBARA	DU	66.00	16.00	
25	CAPSULE-SAN BERNARDINO	DU	33.00	4.00	
26	CAPTIVE-DELANO	DU	66.00	12.00	
27	CARBONIC-CARSON	DU	66.00	12.00	
28	CARDIFF-INLAND	DU	66.00	12.00	
29	CARDIFF-INLAND	DU	66.00	4.00	
30	CARMENITA-WHITTIER	DU	66.00	12.00	
31	CARODEAN-TWENTY-NINE PALMS	DU	115.00	12.00	
32	CAROLINA-FULLERTON	DU	66.00	12.00	
33	CARPINTERIA-CARPINTERIA	DU	66.00	16.00	
34	CARSON-COMPTON	DU	66.00	16.00	
35	CASITAS-VENTURA	DU	66.00	16.00	
36	CATHEDRAL CITY-PALM SPRINGS	DU	33.00	4.80	
37	CEDARWOOD-HUNTINGTON BEACH	DU	12.00	4.00	
38	CERTIFIED-LONG BEACH	DU	66.00	12.00	
39	CHANNEL ISLAND-TEHACHAPI	DU	66.00	16.00	
40	CHASE-ONTARIO	DU	66.00	12.00	

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1	CHATHAM-VISALIA	DU	66.00	12.00	
2	CHATSWORTH-THOUSAND OAK	DU	66.00	16.00	
3	CHERRY-LONG BEACH	DU	66.00	12.00	
4	CHESTNUT-SANTA ANA	DU	66.00	12.00	
5	CHEVCENTRAL-EL SUGUNDO	DU	66.00	16.00	
6	CHIQUITA-EL TORO	DU	66.00	12.00	
7	CITRUS-COVINA	DU	66.00	12.00	
8	CLAREMONT-CLAREMONT	DU	66.00	4.00	
9	CLARK-LONG BEACH	DU	66.00	4.00	
10	COFFEE-PALM SPRINGS	DU	33.00	12.00	
11	COLONIA-VENTURA	DU	66.00	16.00	
12	COLORADO-SANTA MONICA	DU	66.00	16.00	
13	COLORADO-SANTA MONICA	DU	66.00	4.00	
14	COLOSSUS-VALENCIA	DU	66.00	16.00	
15	COLTON-FOOTHILL	DU	66.00	12.00	
16	COLTON CEMENT-COLTON	DU	66.00	12.00	
17	COLUMBINE-DELANO	DU	66.00	12.00	
18	COMPRESS-TORRANCE	DU	66.00	12.00	
19	COMPTON-COMPTON	DU	16.00	4.00	
20	CONCHO-PALM SPRINGS	DU	115.00	12.00	
21	CONVERSE FLATS-CAMP ANGELUS	DU	33.00	12.00	
22	CORNERS-LONG BEACH	DU	66.00	2.40	
23	CORNUTA-COMPTON	DU	66.00	12.00	
24	CORONA-ONTARIO	DU	66.00	33.00	
25	CORONA-ONTARIO	DU	66.00	12.00	
26	CORONA-ONTARIO	DU	33.00	4.00	
27	CORRECTION-TEHACHAPI	DU	66.00	12.00	
28	CORTEZ-COVINA	DU	66.00	12.00	
29	CORUM-LANCASTER	DU	66.00	12.00	
30	COSMIC-HAWTHORNE	DU	66.00	12.00	
31	COSO-LITTLE LAKE	DU	115.00	12.00	
32	COSTA MESA-HUNTINGTON BEACH	DU	12.00	4.00	
33	COTTONWOOD-HI DESERT	DU	115.00	33.00	
34	COVINA-COVINA	DU	12.00	4.00	
35	CRATER-THOUSAND OAK	DU	66.00	16.00	
36	CREST-REDONDO	DU	66.00	16.00	
37	CRESTMORE-RUBIDOUX	DU	66.00	4.00	
38	CROWN-HUNTINGTON BEACH	DU	66.00	12.00	
39	CUCAMONGA-FOOTHILL	DU	66.00	12.00	
40	CUDAHY-COMPTON	DU	66.00	16.00	

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1	CUDAHY-COMPTON	DU	66.00	4.00	
2	CULVER-SANTA MONICA	DU	66.00	16.00	
3	CULVER-SANTA MONICA	DU	66.00	4.00	
4	CUMMINGS-LANCASTER	DU	66.00	12.00	
5	CYBER-EL SEGUNDO	DU	66.00	12.00	
6	CYPRESS-FULLERTON	DU	66.00	12.00	
7	CYPRESS-FULLERTON	DU	12.00	4.00	
8	DAGGETT-BARSTOW	DU	33.00	4.00	
9	DAISY-LONG BEACH	DU	12.00	4.00	
10	DALTON-MONROVIA	DU	66.00	12.00	
11	DATABANK-CORONA	DU	66.00	12.00	
12	DAVIDSON CITY-LONG BEACH	DU	12.00	4.00	
13	DECLEZ-FOOTHILL	DU	66.00	12.00	
14	DECLEZ-FOOTHILL	DU	12.00	4.00	
15	DEFRAIN-BLYTHE	DU	33.00	12.00	
16	DEL MAR-EL SEGUNDO	DU	66.00	13.20	
17	DEL ROSA-INLAND	DU	66.00	12.00	
18	DEL SUR-LANCASTER	DU	66.00	12.00	
19	DELANO-DELANO	DU	66.00	12.00	
20	DELANO-DELANO	DU	66.00	4.00	
21	DESAL-SANTA BARBARA	DU	66.00	12.00	
22	DESERT OUTPOST-CATHEDRAL CITY	DU	33.00	12.00	
23	DIAMOND BAR-COVINA	DU	66.00	12.00	
24	DIEMER-YORBA LINDA	DU	66.00	4.00	
25	DIKE-LONG BEACH	DU	66.00	12.00	
26	DITMAR-REDONDO	DU	66.00	16.00	
27	DITMAR-REDONDO	DU	16.00	4.00	
28	DOCK-LONG BEACH	DU	66.00	25.00	
29	DOHENY-SANTA MONICA	DU	16.00	4.00	
30	DOMHILL-CARSON	DU	66.00	4.00	
31	DOUGLAS-EL SEGUNDO	DU	66.00	16.00	
32	DOUGOIL-PARAMOUNT	DU	66.00	12.00	
33	DOWNEY-WHITTIER	DU	12.00	4.00	
34	DOWNEY MED-WHITTIER	DU	66.00	12.00	
35	DOWNS-RIDGECREST	DU	115.00	12.00	
36	DUARTE-MONROVIA	DU	16.00	4.00	
37	DUNES-BLYTHE	DU	33.00	12.00	
38	DUNN SIDING-HI DESERT	DU	115.00	12.00	
39	EARLIMART-DELANO	DU	66.00	12.00	
40	EAST BARSTOW-HI DESERT	DU	33.00	4.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EATON-MONROVIA	DU	66.00	16.00	
2	EDGEWATER-HUNTINGTON BEACH	DU	12.00	4.00	
3	EDINGER-SANTA ANA	DU	12.00	4.00	
4	EDWARDS-RIDGECREST	DU	115.00	33.00	
5	EISENHOWER-PALM SPRINGS	DU	115.00	33.00	
6	EISENHOWER-PALM SPRINGS	DU	115.00	12.00	
7	EL SOBRANTE-ONTARIO	DU	33.00	12.00	
8	ELCANS-VISALIA	DU	66.00	12.00	
9	ELIZABETH LAKE-VENTURA	DU	66.00	16.00	
10	ELSINORE-SAN JACINTO	DU	115.00	33.00	
11	ELSINORE-SAN JACINTO	DU	115.00	12.00	
12	ELY-FULLERTON	DU	66.00	12.00	
13	ERIC-LONG BEACH	DU	66.00	12.00	
14	ESTERO-VENTURA	DU	66.00	16.00	
15	ESTRELLA-EL TORO	DU	66.00	12.00	
16	EUCLID-ONTARIO	DU	12.00	4.00	
17	FAIR OAKS-MONROVIA	DU	16.00	4.00	
18	FAIRFAX-LOS ANGELES	DU	66.00	16.00	
19	FAIRFAX-LOS ANGELES	DU	16.00	4.00	
20	FAIRVIEW-SANTA ANA	DU	66.00	12.00	
21	FARRELL-PALM SPRINGS	DU	115.00	12.00	
22	FELTON-INGLEWOOD	DU	66.00	16.00	
23	FELTON-INGLEWOOD	DU	16.00	4.00	
24	FERNWOOD-COMPTON	DU	66.00	16.00	
25	FIBRE-RIVERSIDE	DU	66.00	4.00	
26	FILLMORE-VENTURA	DU	66.00	16.00	
27	FIREHOUSE-ONTARIO	DU	66.00	12.00	
28	FLANCO-FOOTHILL	DU	12.00	4.00	
29	FLORADAY-WHITTIER	DU	12.00	4.00	
30	FOGARTY-LITTLE LAKE	DU	115.00	12.00	
31	FOREST HOME-INLAND	DU	33.00	2.40	
32	FORGE-RANCHO CUCAMONGA	DU	66.00	12.00	
33	FORT IRWIN-FORT IRWIN	DU	33.00	12.00	
34	FRANCIS-ONTARIO	DU	66.00	12.00	
35	FRAZIER PARK-LANCASTER	DU	66.00	12.00	
36	FREMONT-COMPTON	DU	66.00	16.00	
37	FREMONT-COMPTON	DU	16.00	4.00	
38	FRIENDLY HILLS-WHITTIER	DU	12.00	4.00	
39	FRUITLAND-COMPTON	DU	66.00	16.00	
40	FRUITLAND-COMPTON	DU	66.00	4.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FUEL-LONG BEACH	DU	66.00	4.00	
2	FULLERTON-FULLERTON	DU	66.00	12.00	
3	FULLERTON-FULLERTON	DU	66.00	4.00	
4	GAGE-COMPTON	DU	16.00	4.00	
5	GALAXY-MANHATTAN BEACH	DU	66.00	12.00	
6	GALAXY-MANHATTAN BEACH	DU	66.00	4.00	
7	GALE-HI DESERT	DU	115.00	33.00	
8	GALLATIN-WHITTIER	DU	66.00	12.00	
9	GANESHA-COVINA	DU	66.00	12.00	
10	GANESHA-COVINA	DU	12.00	4.00	
11	GARFIELD-EL MONTE	DU	66.00	4.00	
12	GARNET-PALM SPRINGS	DU	115.00	33.00	
13	GARNET-PALM SPRINGS	DU	33.00	12.00	
14	GARVEY-MONTEBELLO	DU	16.00	4.00	
15	GATX-CARSON	DU	66.00	12.00	
16	GAVILAN-SAN JACINTO	DU	33.00	12.00	
17	GAVIOTA-SANTA BARBARA	DU	66.00	16.00	
18	GENAMIC-RANCHO CUCAMONGA	DU	66.00	12.00	
19	GEORGE A.F.B.-ADELANTO	DU	33.00	4.00	
20	GETTY-VENTURA	DU	66.00	16.00	
21	GILBERT-FULLERTON	DU	66.00	12.00	
22	GISLER-HUNTINGTON BEACH	DU	66.00	12.00	
23	GLEN AVON-ONTARIO	DU	66.00	12.00	
24	GLEN IVY-GLEN IVY HOT	DU	33.00	12.00	
25	GLENNVILLE-DELANO	DU	66.00	12.00	
26	GOLDSTONE-BARSTOW	DU	33.00	12.00	
27	GOLDTOWN-LANCASTER	DU	66.00	12.00	
28	GONZALES-VENTURA	DU	66.00	16.00	
29	GORMAN-LANCASTER	DU	66.00	12.00	
30	GOSHEN-VISALIA	DU	66.00	12.00	
31	GRAHAM-COMPTON	DU	16.00	4.00	
32	GRANADA-MONTEBELLO	DU	16.00	4.00	
33	GREAT LAKES-ROSAMOND	DU	66.00	12.00	
34	GREENHORN-DELANO	DU	66.00	2.40	
35	GREENING-LONG BEACH	DU	66.00	12.00	
36	HAAGEN-TULARE	DU	66.00	4.00	
37	HAMILTON-HUNTINGTON BEACH	DU	66.00	12.00	
38	HANFORD-HANFORD	DU	66.00	4.00	
39	HANJIN-LONG BEACH	DU	66.00	12.00	
40	HARDING-MONTEBELLO	DU	16.00	4.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HARPER LAKE-HI DESERT	DU	33.00	4.80	
2	HARVARD-HI DESERT	DU	33.00	12.00	
3	HASKELL-SAN FERNANDO	DU	66.00	16.00	
4	HATHAWAY-LONG BEACH	DU	66.00	12.00	
5	HATHAWAY-LONG BEACH	DU	66.00	4.00	
6	HAVASU-BLYTHE	DU	66.00	16.00	
7	HAVEDA-REDONDO	DU	16.00	4.00	
8	HAVILAH-KERNVILLE	DU	66.00	12.00	
9	HEDDA-LONG BEACH	DU	12.00	4.00	
10	HELENDALE-HI DESERT	DU	33.00	12.00	
11	HELIJET-PALMDALE	DU	66.00	12.00	
12	HELIJET-PALMDALE	DU	12.00	4.00	
13	HEMET-SAN JACINTO	DU	33.00	12.00	
14	HESPERIA-HI DESERT	DU	115.00	12.00	
15	HI DESERT-TWENTY-NINE PALMS	DU	115.00	33.00	
16	HI DESERT-TWENTY-NINE PALMS	DU	35.00	24.90	
17	HIGHLAND-INLAND	DU	66.00	12.00	
18	HINKLEY-HI DESERT	DU	33.00	12.00	
19	HOLGATE-BORON	DU	33.00	12.00	
20	HOLIDAY-PALM SPRINGS	DU	33.00	4.00	
21	HOMART-INLAND	DU	115.00	12.00	
22	HOPEFUL-DUARTE	DU	66.00	12.00	
23	HOWARD-INGLEWOOD	DU	66.00	4.00	
24	HOYT-EL MONTE	DU	16.00	4.00	
25	HUGHESAIR-EL SEGUNDO	DU	66.00	12.00	
26	HUGHTRON-TORRANCE	DU	66.00	4.00	
27	HUNTINGTON PARK-COMPTON	DU	16.00	4.00	
28	HUSTON-ARROWHEAD	DU	33.00	12.00	
29	HUSTON-ARROWHEAD	DU	33.00	2.40	
30	IDYLLWILD-SAN JACINTO	DU	33.00	12.00	
31	IDYLLWILD-SAN JACINTO	DU	33.00	2.40	
32	IMPERIAL-WHITTIER	DU	66.00	12.00	
33	IMPERIAL-WHITTIER	DU	66.00	4.00	
34	INDIAN WELLS-PALM SPRINGS	DU	115.00	12.00	
35	INDUSTRY-COVINA	DU	66.00	12.00	
36	INGLEWOOD-INGLEWOOD	DU	66.00	16.00	
37	INGLEWOOD-INGLEWOOD	DU	66.00	4.00	
38	INJECTION-LONG BEACH	DU	66.00	12.00	
39	INLAND-ONTARIO	DU	66.00	12.00	
40	INYOKERN-RIDGECREST	DU	115.00	33.00	

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1	INYOKERN-RIDGECREST	DU	33.00	12.00	
2	INYOKERN TOWN-RIDGECREST	DU	33.00	4.80	
3	IRON MT. SCE-DESERT CENTER	DU	16.00	6.90	
4	IRVINE-EL TORO	DU	66.00	12.00	
5	ISABELLA-KERNVILLE	DU	66.00	12.00	
6	ISLA VISTA-SANTA BARBARA	DU	66.00	16.00	
7	ISLA VISTA-SANTA BARBARA	DU	66.00	12.00	
8	IVAR-MONTEBELLO	DU	16.00	4.00	
9	IVYGLEN-ONTARIO	DU	115.00	12.00	
10	JEFFERSON-ONTARIO	DU	66.00	12.00	
11	JERSEY-COMPTON	DU	66.00	16.00	
12	JOSHUA TREE-TWENTY-NINE PALMS	DU	33.00	12.00	
13	KEMPSTER-FOOTHILL	DU	33.00	4.00	
14	KERNVILLE-KERNVILLE	DU	66.00	16.00	
15	KERNVILLE-KERNVILLE	DU	66.00	12.00	
16	KIMBALL-CHINO	DU	66.00	12.00	
17	LA CANADA-MONROVIA	DU	66.00	16.00	
18	LA CANADA-MONROVIA	DU	16.00	4.00	
19	LA HABRA-FULLERTON	DU	66.00	12.00	
20	LA MIRADA-WHITTIER	DU	66.00	12.00	
21	LA PALMA-FULLERTON	DU	66.00	12.00	
22	LA VETA-SANTA ANA	DU	66.00	12.00	
23	LAFAYETTE-HUNTINGTON BEACH	DU	66.00	12.00	
24	LAKEWOOD-LONG BEACH	DU	66.00	4.00	
25	LAKEVIEW-NUEVO	DU	115.00	12.00	
26	LAMPSON-SANTA ANA	DU	66.00	12.00	
27	LANCASTER-LANCASTER	DU	66.00	12.00	
28	LANCASTER-LANCASTER	DU	12.00	4.00	
29	LANDING-BLYTHE	DU	66.00	16.00	
30	LARDER-LONG BEACH	DU	12.00	4.00	
31	LARK ELLEN-COVINA	DU	66.00	12.00	
32	LAS LOMAS-IRVINE	DU	66.00	12.00	
33	LATIGO-THOUSAND OAK	DU	66.00	16.00	
34	LAUREL-TULARE	DU	66.00	12.00	
35	LAWNDALE-INGLEWOOD	DU	16.00	4.00	
36	LAYFAIR-COVINA	DU	66.00	12.00	
37	LAYFAIR-COVINA	DU	66.00	4.00	
38	LEATHERNECK-TWENTY-NINE PALMS	DU	115.00	34.50	
39	LEHMAN-OXNARD	DU	66.00	12.00	
40	LEMON COVE-VISALIA	DU	66.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LENNOX-INGLEWOOD	DU	66.00	16.00	
2	LENNOX-INGLEWOOD	DU	16.00	4.00	
3	LEVY-VENTURA	DU	66.00	16.00	
4	LIBERTY-VISALIA	DU	66.00	12.00	
5	LIMESTONE-EL TORO	DU	66.00	12.00	
6	LINDEN-LONG BEACH	DU	12.00	4.00	
7	LINDSAY-PORTERVILLE	DU	66.00	12.00	
8	LINDSAY-PORTERVILLE	DU	66.00	4.00	
9	LIQUID-IRWINDALE	DU	66.00	4.00	
10	LITTLE ROCK-PALMDALE	DU	66.00	12.00	
11	LIVE OAK-COVINA	DU	66.00	12.00	
12	LOCKHEED-SAUGUS	DU	66.00	16.00	
13	LOCKHEED-SAUGUS	DU	66.00	12.00	
14	LOCUST-LONG BEACH	DU	12.00	4.00	
15	LONGDON-COMPTON	DU	16.00	4.00	
16	LORAINE-LANCASTER	DU	66.00	12.00	
17	LOS CERRITOS-LONG BEACH	DU	66.00	12.00	
18	LOS CERRITOS-LONG BEACH	DU	12.00	4.00	
19	LOSULFUR-EL SEGUNDO	DU	66.00	13.20	
20	LUCAS-LONG BEACH	DU	66.00	12.00	
21	LUCAS-LONG BEACH	DU	66.00	4.00	
22	LUCERNE-HI DESERT	DU	33.00	12.00	
23	LUNADA-REDONDO	DU	16.00	4.00	
24	LYNWOOD-COMPTON	DU	16.00	4.00	
25	MACARTHUR-HUNTINGTON BEACH	DU	66.00	12.00	
26	MACNEIL-BURBANK	DU	66.00	12.00	
27	MADRID-REDONDO	DU	16.00	4.00	
28	MALIBU-THOUSAND OAK	DU	66.00	16.00	
29	MANHATTAN-REDONDO	DU	16.00	4.00	
30	MARASCHINO-INLAND	DU	115.00	12.00	
31	MARINE-SANTA MONICA	DU	66.00	16.00	
32	MARION-FULLERTON	DU	66.00	12.00	
33	MARIPOSA-DELANO	DU	66.00	12.00	
34	MARYMOUNT-REDONDO	DU	66.00	16.00	
35	MASCOT-HANFORD	DU	66.00	12.00	
36	MAXWELL-SAN JACINTO	DU	115.00	12.00	
37	MAYBERRY-SAN JACINTO	DU	115.00	12.00	
38	MAYFLOWER-MONROVIA	DU	16.00	4.00	
39	MENTONE-INLAND	DU	115.00	12.00	
40	MERCED-COVINA	DU	66.00	12.00	

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1	MICHILLINDA-MONROVIA	DU	16.00	4.00	
2	MILITARY-TEMECULA	DU	33.00	12.00	
3	MILLIKEN-INLAND	DU	66.00	12.00	
4	MINNEOLA-HI DESERT	DU	33.00	12.00	
5	MISSILE-POINT MUGU	DU	66.00	16.00	
6	MOBILE SUBSTATIONS-TORRANCE	DU	115.00	33.00	
7	MOBILE SUBSTATIONS-TORRANCE	DU	66.00	2.40	
8	MOBILE SUBSTATIONS-TORRANCE	DU	33.00	4.00	
9	MOBILE SUBSTATIONS-TORRANCE	DU	33.00	2.40	
10	MOBILE SUBSTATIONS-TORRANCE	DU	16.00	2.40	
11	MOBILE SUBSTATIONS-TORRANCE	DU	12.00	2.40	
12	MOBILOIL-TORRANCE	DU	66.00	12.00	
13	MOBILOIL-TORRANCE	DU	12.00	2.40	
14	MOBILOIL-TORRANCE	DU	12.00	0.48	
15	MODENA-SANTA ANA	DU	66.00	12.00	
16	MODOC-SANTA BARBARA	DU	16.00	4.00	
17	MONETA-REDONDO	DU	16.00	4.00	
18	MONOLITH-LANCASTER	DU	66.00	12.00	
19	MONROVIA-MONROVIA	DU	16.00	4.00	
20	MONTEBELLO-MONTEBELLO	DU	16.00	4.00	
21	MONTECITO-SANTA BARBARA	DU	16.00	4.00	
22	MOOG-TORRANCE	DU	66.00	12.00	
23	MORAGA-TEMECULA	DU	115.00	12.00	
24	MORENO-MORENO VALLEY	DU	115.00	12.00	
25	MORNINGSIDE-INGLEWOOD	DU	16.00	4.00	
26	MORRO-EL TORO	DU	66.00	12.00	
27	MOULTON-EL TORO	DU	66.00	12.00	
28	MOUNTAIN PASS-HI DESERT	DU	115.00	33.00	
29	MOUNTAIN PASS-HI DESERT	DU	33.00	12.00	
30	MOVIE-CULVER CITY	DU	66.00	16.00	
31	MT. VERNON-INLAND	DU	33.00	4.00	
32	MURPHY-WHITTIER	DU	66.00	12.00	
33	MURRIETTA 2-SAN JACINTO	DU	33.00	12.00	
34	MUSCOY-INLAND	DU	33.00	4.00	
35	NAOMI-COMPTON	DU	16.00	4.00	
36	NAPLES-LONG BEACH	DU	12.00	4.00	
37	NAROD-ONTARIO	DU	66.00	12.00	
38	NARROWS-WHITTIER	DU	66.00	12.00	
39	NAVY MOLE-LONG BEACH	DU	66.00	12.00	
40	NEENACH-LANCASTER	DU	66.00	12.00	

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1	NELSON-SAN JACINTO	DU	115.00	33.00	
2	NELSON-SAN JACINTO	DU	115.00	12.00	
3	NEPTUNE-LONG BEACH	DU	66.00	12.00	
4	NEPTUNE-LONG BEACH	DU	66.00	4.00	
5	NEWBURY-THOUSAND OAK	DU	66.00	16.00	
6	NEWCOMB-SAN JACINTO	DU	115.00	12.00	
7	NEWHALL-SAN FERNANDO	DU	66.00	16.00	
8	NEWMARK-MONTEBELLO	DU	66.00	16.00	
9	NEWMARK-MONTEBELLO	DU	66.00	4.00	
10	NIGUEL-EL TORO	DU	66.00	12.00	
11	NIGUEL-EL TORO	DU	66.00	4.00	
12	NOGALES-COVINA	DU	66.00	12.00	
13	NOLA-COMPTON	DU	66.00	16.00	
14	NORCO-ONTARIO	DU	12.00	4.00	
15	NORSEAL-SEAL BEACH	DU	66.00	12.00	
16	NORTH INTAKE-BLYTHE	DU	33.00	12.00	
17	NORTH MUROC-RIDGECREST	DU	33.00	12.00	
18	NORTH OAKS-SAN FERNANDO	DU	66.00	16.00	
19	NORTHROP-HAWTHORNE	DU	66.00	4.00	
20	NORTHWIND-LANCASTER	DU	66.00	12.00	
21	NORWELD-BREA	DU	66.00	12.00	
22	NUEVO-SAN JACINTO	DU	33.00	12.00	
23	NUGGET-TWENTY-NINE PALMS	DU	35.00	24.90	
24	OAK GROVE-VISALIA	DU	66.00	12.00	
25	OAK PARK-THOUSAND OAK	DU	66.00	16.00	
26	OASIS-LANCASTER	DU	66.00	12.00	
27	OCEAN PARK-SANTA MONICA	DU	16.00	4.00	
28	OCEANVIEW-HUNTINGTON BEACH	DU	66.00	12.00	
29	OCTOL-TULARE	DU	66.00	12.00	
30	OJAI-VENTURA	DU	66.00	16.00	
31	OJAI-VENTURA	DU	66.00	16.00	
32	OLDFIELD-LONG BEACH	DU	12.00	4.00	
33	OLIVE LAKE-BLYTHE	DU	33.00	12.00	
34	OLYMPIC-SANTA MONICA	DU	16.00	4.00	
35	ONEILL-RANCHO SANTA	DU	66.00	12.00	
36	ONSHORE-ELLWOOD	DU	66.00	12.00	
37	ONTARIO-ONTARIO	DU	12.00	2.40	
38	ORANGE-SANTA ANA	DU	66.00	12.00	
39	ORANGE PRODUCTS-ONTARIO	DU	66.00	12.00	
40	ORCOSAN-FOUNTAIN VALLEY	DU	66.00	12.00	

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	ORDWAY-HI DESERT	DU	33.00	12.00	
2	ORO GRANDE-HI DESERT	DU	33.00	12.00	
3	ORTEGA-SANTA BARBARA	DU	66.00	33.00	2.40
4	OXNARD-VENTURA	DU	16.00	4.00	
5	PACLINE-CARSON	DU	66.00	2.40	
6	PALM CANYON-PALM SPRINGS	DU	33.00	12.00	
7	PALM CANYON-PALM SPRINGS	DU	33.00	4.00	
8	PALM SPRINGS-PALM SPRINGS	DU	33.00	4.00	
9	PALM VILLAGE-PALM SPRINGS	DU	33.00	12.00	
10	PALM VILLAGE-PALM SPRINGS	DU	33.00	4.80	
11	PALMDALE-LANCASTER	DU	66.00	12.00	
12	PALOS VERDES-REDONDO	DU	16.00	4.00	
13	PAPER-FULLERTON	DU	66.00	4.00	
14	PAPER-FULLERTON	DU	14.00	4.16	
15	PARKWOOD-FULLERTON	DU	66.00	12.00	
16	PASSONS-WHITTIER	DU	66.00	12.00	
17	PAUBA-SAN JACINTO	DU	115.00	12.00	
18	PAULARINO-HUNTINGTON BEACH	DU	12.00	4.00	
19	PEARL-SANTA MONICA	DU	16.00	4.00	
20	PECHANGA-SAN JACINTO	DU	115.00	33.00	
21	PECHANGA-SAN JACINTO	DU	115.00	12.00	
22	PEDLEY-ONTARIO	DU	66.00	12.00	
23	PEERLESS-RIDGECREST	DU	33.00	12.00	
24	PEPPER-INLAND	DU	115.00	12.00	
25	PEREZ-ONTARIO	DU	33.00	4.00	
26	PERRY-REDONDO	DU	16.00	4.00	
27	PERRY-REDONDO	DU	16.00	4.00	
28	PEYTON-ONTARIO	DU	66.00	12.00	
29	PHARMACY-THOUSAND OAK	DU	66.00	16.00	
30	PHELAN-HI DESERT	DU	115.00	33.00	
31	PHELAN-HI DESERT	DU	115.00	12.00	
32	PICO-LONG BEACH	DU	66.00	12.00	
33	PIER-LONG BEACH	DU	66.00	12.00	
34	PIERPONT-VENTURA	DU	16.00	4.00	
35	PIONEER-WHITTIER	DU	66.00	12.00	
36	PIONEER-WHITTIER	DU	12.00	4.00	
37	PIPE-ETIWANDA	DU	66.00	12.00	
38	PIUTE-LANCASTER	DU	66.00	12.00	
39	PIXLEY-DELANO	DU	66.00	12.00	
40	PLACENTIA-FULLERTON	DU	66.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PLASTER-SOUTH GATE	DU	66.00	2.40	
2	PLASTIC-CHINO	DU	66.00	12.00	
3	PLAYA-SANTA BARBARA	DU	16.00	4.00	
4	PLAYA-SANTA BARBARA	DU	16.00	4.00	
5	POLARIS-EL SEGUNDO	DU	66.00	4.00	
6	POLARIS-EL SEGUNDO	DU	16.00	4.00	
7	POMONA-COVINA	DU	12.00	4.00	
8	POPLAR-PORTERVILLE	DU	66.00	12.00	
9	POPLAR-PORTERVILLE	DU	66.00	12.00	
10	PORTERVILLE-PORTERVILLE	DU	66.00	12.00	
11	PORTERVILLE-PORTERVILLE	DU	66.00	4.00	
12	POTRERO-THOUSAND OAK	DU	66.00	16.00	
13	PROCESS-LONG BEACH	DU	66.00	12.00	
14	PROCTOR-COMPTON	DU	66.00	12.00	
15	PROTEIN-TULARE	DU	66.00	12.00	
16	PUENTE-COVINA	DU	66.00	12.00	
17	PUREWATER-REDLANDS	DU	115.00	4.00	
18	QUARTZ HILL-LANCASTER	DU	66.00	12.00	
19	QUINN-DELANO	DU	66.00	12.00	
20	RAILROAD-COVINA	DU	66.00	12.00	
21	RALPHS-COMPTON	DU	66.00	4.00	
22	RAMONA-MONTEBELLO	DU	66.00	4.00	
23	RANCHO-HI DESERT	DU	33.00	12.00	
24	RANDALL-FOOTHILL	DU	66.00	12.00	
25	RANDOLPH-COMPTON	DU	66.00	16.00	
26	RANDSBURG-RIDGECREST	DU	115.00	33.00	
27	RAVENDALE-MONTEBELLO	DU	66.00	16.00	
28	RAVENDALE-MONTEBELLO	DU	66.00	4.00	
29	RECOVERY-HUNTINGTON BEACH	DU	66.00	12.00	
30	RECTIFIER-TEMECULA	DU	115.00	33.00	
31	REDLANDS-INLAND	DU	66.00	12.00	
32	REDLANDS-INLAND	DU	66.00	4.00	
33	REDMAN-LANCASTER	DU	66.00	12.00	
34	REDONDO-REDONDO	DU	16.00	4.00	
35	REDUCTION-ETIWANDA	DU	66.00	12.00	
36	REDUCTION-ETIWANDA	DU	66.00	4.00	
37	REFINERY-CARSON	DU	66.00	12.00	
38	REFUSE-COMMERCE	DU	66.00	12.00	
39	RENO-INDUSTRY	DU	66.00	4.00	
40	REPETTO-MONTEBELLO	DU	66.00	16.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	REPETTO-MONTEBELLO	DU	66.00	4.00	
2	RIALTO-FOOTHILL	DU	33.00	12.00	
3	RIALTO-FOOTHILL	DU	33.00	4.00	
4	RIDGECREST-RIDGECREST	DU	33.00	4.80	
5	RINGMILL-PARAMOUNT	DU	66.00	4.00	
6	RIPLEY-BLYTHE	DU	33.00	12.00	
7	RITEAID-LANCASTER	DU	66.00	12.00	
8	RITTER RANCH-PALMDALE	DU	66.00	12.00	
9	RIVERA-WHITTIER	DU	12.00	4.00	
10	RIVERTEX-ORO GRANDE	DU	115.00	13.80	
11	RIVERWAY-VISALIA	DU	66.00	12.00	
12	ROADWAY-HI DESERT	DU	115.00	12.00	
13	ROCKAIR-PALMDALE	DU	66.00	12.00	
14	ROCKET TEST-BORON	DU	115.00	33.00	
15	ROLLING HILLS-REDONDO	DU	66.00	16.00	
16	ROLLING HILLS-REDONDO	DU	66.00	4.00	
17	ROSAMOND-LANCASTER	DU	66.00	12.00	
18	ROSECRANS-EL SEGUNDO	DU	66.00	16.00	
19	ROSEMEAD-MONTEBELLO	DU	66.00	16.00	
20	ROYAL-SIMI VALLEY	DU	66.00	16.00	
21	RUBIDOUX-RUBIDOUX	DU	33.00	12.00	
22	RUBIDOUX-RUBIDOUX	DU	33.00	4.00	
23	RUNNING SPRINGS-ARROWHEAD	DU	33.00	12.00	
24	RUSH-MONTEBELLO	DU	66.00	16.00	
25	SAN ANTONIO-COVINA	DU	66.00	12.00	
26	SAN DIMAS-COVINA	DU	66.00	12.00	
27	SAN FERNANDO-SAN FERNANDO	DU	66.00	16.00	
28	SAN GABRIEL-MONTEBELLO	DU	66.00	4.00	
29	SAN MARCOS-SANTA BARBARA	DU	66.00	16.00	
30	SAN MARINO-MONROVIA	DU	16.00	4.00	
31	SAN MIGUEL-VENTURA	DU	66.00	16.00	
32	SAN VICENTE-SANTA MONICA	DU	16.00	4.00	
33	SANGAR-MONROVIA	DU	16.00	4.00	
34	SANTA BARBARA-SANTA BARBARA	DU	66.00	16.00	
35	SANTA BARBARA-SANTA BARBARA	DU	66.00	4.00	
36	SANTA FE SPRINGS-WHITTIER	DU	66.00	12.00	
37	SANTA FE SPRINGS-WHITTIER	DU	66.00	12.00	
38	SANTA MONICA-SANTA MONICA	DU	66.00	16.00	
39	SANTA MONICA-SANTA MONICA	DU	66.00	4.00	
40	SANTA ROSA-PALM SPRINGS	DU	115.00	33.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SANTA ROSA-PALM SPRINGS	DU	115.00	12.00	
2	SANTA SUSANA-THOUSAND OAK	DU	66.00	16.00	
3	SANTEE-INDUSTRY	DU	66.00	12.00	
4	SATICOY-VENTURA	DU	66.00	16.00	
5	SAVAGE-HESPERIA	DU	115.00	12.00	
6	SAWTELLE-SANTA MONICA	DU	66.00	16.00	
7	SEABRIGHT-LONG BEACH	DU	66.00	12.00	
8	SEARLES-RIDGECREST	DU	115.00	33.00	
9	SECOND AVENUE-BLYTHE	DU	33.00	12.00	
10	SEPULVEDA-INGLEWOOD	DU	66.00	16.00	
11	SEPULVEDA-INGLEWOOD	DU	16.00	4.00	
12	SERVER-EL SEGUNDO	DU	66.00	16.00	
13	SHANDIN-INLAND	DU	115.00	12.00	
14	SHARON-MONROVIA	DU	16.00	4.00	
15	SHAWNEE-HUNTINGTON BEACH	DU	66.00	12.00	
16	SHELLINE-CALABASAS	DU	66.00	12.00	
17	SHELLSOM-SOMIS	DU	66.00	2.40	
18	SHELLWATT-CARSON	DU	66.00	12.00	
19	SHIP-LONG BEACH	DU	66.00	12.00	
20	SHRED-SOUTHGATE	DU	66.00	12.00	
21	SHULTZ-SOUTH GATE	DU	66.00	16.00	
22	SHUTTLE-LANCASTER	DU	66.00	12.00	
23	SIERRA MADRE-MONROVIA	DU	16.00	4.00	
24	SIGNAL HILL-LONG BEACH	DU	66.00	12.00	
25	SIGNAL HILL-LONG BEACH	DU	12.00	4.00	
26	SILVER SPUR-PALM SPRINGS	DU	33.00	12.00	
27	SIXTEENTH STREET-INLAND	DU	33.00	12.00	
28	SKYLARK-SAN JACINTO	DU	115.00	12.00	
29	SLATER-HUNTINGTON BEACH	DU	66.00	12.00	
30	SMILEY-INLAND	DU	12.00	4.00	
31	SOCO-HUNTINGTON BEACH	DU	66.00	33.00	
32	SOLEMINT-SAN FERNANDO	DU	66.00	16.00	
33	SOMERSET-COMPTON	DU	66.00	12.00	
34	SOMERSET-COMPTON	DU	66.00	4.00	
35	SOMIS-VENTURA	DU	66.00	16.00	
36	SONY-CULVER CITY	DU	66.00	16.00	
37	SOPIPE-INDUSTRY	DU	66.00	4.00	
38	SOQUEL-CHINO HILLS	DU	66.00	12.00	
39	SOUTH GATE-COMPTON	DU	16.00	4.00	
40	SOUTHBASE-E.A.F.B.	DU	115.00	33.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTHPAC-NORWALK	DU	66.00	2.40	
2	SPACE-REDONDO BEACH	DU	66.00	4.00	
3	SPONGE-PICO RIVERA	DU	66.00	2.40	
4	STADIUM-LONG BEACH	DU	66.00	12.00	
5	STADIUM-LONG BEACH	DU	66.00	12.00	
6	STADLER-SAN JACINTO	DU	115.00	12.00	
7	STANHILL-INGLEWOOD	DU	66.00	12.00	
8	STATE STREET-LONG BEACH	DU	66.00	12.00	
9	STENT-TEMECULA	DU	115.00	12.00	
10	STETSON-SAN JACINTO	DU	115.00	12.00	
11	STEVEDORE-LONG BEACH	DU	66.00	12.00	
12	STEWART-WHITTIER	DU	66.00	12.00	
13	STIRRUP-REDONDO	DU	16.00	4.00	
14	STODDARD-INLAND	DU	33.00	4.00	
15	STRATHMORE-PORTERVILLE	DU	66.00	12.00	
16	STRATHMORE-PORTERVILLE	DU	66.00	12.00	
17	SULLIVAN-SANTA ANA	DU	66.00	12.00	
18	SULLIVAN-SANTA ANA	DU	66.00	12.00	
19	SULLIVAN-SANTA ANA	DU	66.00	4.00	
20	SUN CITY-SAN JACINTO	DU	115.00	12.00	
21	SUNNY DUNES-PALM SPRINGS	DU	33.00	4.00	
22	SUNNYHILLS-FULLERTON	DU	66.00	12.00	
23	SUNNYSIDE-LONG BEACH	DU	66.00	12.00	
24	SUNNYSIDE-LONG BEACH	DU	66.00	4.00	
25	TAHITI-SANTA MONICA	DU	66.00	16.00	
26	TAHITI-SANTA MONICA	DU	66.00	12.00	
27	TALBERT-SANTA ANA	DU	66.00	12.00	
28	TAMARISK-PALM SPRINGS	DU	115.00	12.00	
29	TAPIA-THOUSAND OAK	DU	66.00	16.00	
30	TEAM-WESTMINSTER	DU	66.00	12.00	
31	TELEGRAPH-WHITTIER	DU	66.00	12.00	
32	TEMPLE-MONROVIA	DU	16.00	4.00	
33	TENAJA-MURRIETA	DU	115.00	12.00	
34	TENNESSEE-INLAND	DU	66.00	12.00	
35	TERRA BELLA-PORTERVILLE	DU	66.00	12.00	
36	TERRA BELLA-PORTERVILLE	DU	66.00	12.00	
37	TERRACE-MONTEBELLO	DU	16.00	4.00	
38	THORNHILL-PALM SPRINGS	DU	115.00	12.00	
39	THOUSAND OAKS-THOUSAND OAK	DU	66.00	16.00	
40	THREE RIVERS-VISALIA	DU	66.00	12.00	

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1	THRIVE-FONTANA	DU	66.00	12.00	
2	THRUST-CHATSWORTH	DU	66.00	4.00	
3	THUMS ISLAND A-ISLAND GRISSOM-LONG BEACH	DU	66.00	4.00	
4	THUMS ISLAND B-ISLAND WHITE-LONG BEACH	DU	66.00	4.00	
5	THUMS ISLAND C-ISLAND CHAFFEE-LONG BEACH	DU	66.00	4.00	
6	THUMS ISLAND D-ISLAND FREEMAN-LONG BEACH	DU	66.00	4.00	
7	THUNDERBIRD-PALM SPRINGS	DU	33.00	4.80	
8	TIDELANDS-LONG BEACH	DU	66.00	12.00	
9	TIEFORT-HI DESERT	DU	115.00	33.00	
10	TIMOTEO-INLAND	DU	66.00	12.00	
11	TIPPECANOE-INLAND	DU	12.00	4.00	
12	TIPTON-TULARE	DU	66.00	12.00	
13	TOPANGA-THOUSAND OAK	DU	16.00	4.00	
14	TOPAZ-REDONDO	DU	66.00	4.00	
15	TORRANCE-REDONDO	DU	66.00	16.00	
16	TORREY-PIRU	DU	66.00	16.00	
17	TORTILLA-HI DESERT	DU	115.00	33.00	
18	TORTILLA-HI DESERT	DU	115.00	12.00	
19	TOYOTA-LONG BEACH	DU	66.00	12.00	
20	TRASK-SANTA ANA	DU	66.00	12.00	
21	TRITON-RANCHO PALO VERDE	DU	115.00	12.00	
22	TRONA-RIDGECREST	DU	33.00	12.00	
23	TROPHY-COVINA	DU	66.00	12.00	
24	TULARE-TULARE	DU	66.00	12.00	
25	TWENTYNINE PALMS-TWENTY-NINE PALMS	DU	33.00	12.00	
26	TWENTYNINE PALMS-TWENTY-NINE PALMS	DU	33.00	4.80	
27	UNIOIL-OXNARD	DU	66.00	16.00	
28	UNIVERSAL-UNIVERSAL CITY	DU	66.00	12.00	
29	UPLAND-FOOTHILL	DU	66.00	12.00	
30	UPLAND-FOOTHILL	DU	66.00	4.00	
31	VAIL-MONTEBELLO	DU	66.00	16.00	
32	VALDEZ-THOUSAND OAK	DU	66.00	16.00	
33	VALENCIA-INLAND	DU	12.00	4.00	
34	VARWIND-MOJAVE	DU	66.00	12.00	
35	VEGAS-SANTA BARBARA	DU	66.00	16.00	
36	VENICE HILL-VISALIA	DU	66.00	12.00	
37	VENIDA-VISALIA	DU	66.00	12.00	
38	VENTURA-VENTURA	DU	16.00	4.00	
39	VERA-SANTA ANA	DU	66.00	12.00	
40	VERDANT-BLYTHE	DU	33.00	12.00	

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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	VICTORIA-REDONDO	DU	66.00	16.00	
2	VICTORVILLE-HI DESERT	DU	33.00	12.00	
3	VICTORVILLE-HI DESERT	DU	33.00	4.00	
4	VISALIA-VISALIA	DU	66.00	12.00	
5	VISALIA-VISALIA	DU	66.00	4.00	
6	WABASH-MONTEBELLO	DU	66.00	16.00	
7	WAKEFIELD-VENTURA	DU	66.00	16.00	
8	WALKER BASIN-KERNVILLE	DU	66.00	12.00	
9	WALTERIA-REDONDO	DU	66.00	16.00	
10	WALTERIA-REDONDO	DU	66.00	4.00	
11	WASHINGTON-SANTA ANA	DU	66.00	12.00	
12	WASTEWATER-OXNARD	DU	66.00	16.00	
13	WATSON-COMPTON	DU	66.00	12.00	
14	WAVE-HUNTINGTON BEACH	DU	66.00	12.00	
15	WAVE-HUNTINGTON BEACH	DU	12.00	4.00	
16	WEBCO-PARAMOUNT	DU	66.00	4.00	
17	WELDON-KERNVILLE	DU	66.00	12.00	
18	WESBASIN-EL SEGUNDO	DU	66.00	16.00	
19	WEST BARSTOW-HI DESERT	DU	33.00	4.00	
20	WEST RIVERSIDE-ONTARIO	DU	33.00	12.00	
21	WESTEX-SIGNAL HILL	DU	66.00	12.00	
22	WESTGATE-WHITTIER	DU	12.00	4.00	
23	WESTHILL-EL SEGUNDO	DU	66.00	16.00	
24	WESTPAC-GORMAN	DU	66.00	4.00	
25	WEYMOUTH-LA VERNE	DU	66.00	4.00	
26	WHARF-LONG BEACH	DU	66.00	12.00	
27	WHEATLAND-DELANO	DU	66.00	12.00	
28	WHIPPLE-BLYTHE	DU	66.00	33.00	
29	WHITEWATER-PALM SPRINGS	DU	33.00	4.00	
30	WILSONA-LANCASTER	DU	66.00	12.00	
31	WIMBLEDON-FOOTHILL	DU	66.00	12.00	
32	WINDSOR HILLS-INGLEWOOD	DU	66.00	16.00	
33	WINDSOR HILLS-INGLEWOOD	DU	16.00	4.00	
34	WOODRUFF-COMPTON	DU	12.00	4.00	
35	WOODVILLE-PORTERVILLE	DU	66.00	12.00	
36	WRIGHTWOOD-HI DESERT	DU	33.00	12.00	
37	WRIGHTWOOD-HI DESERT	DU	12.00	2.40	
38	YERMO-HI DESERT	DU	33.00	12.00	
39	YORBA LINDA-FULLERTON	DU	66.00	12.00	
40	YUCAIPA-INLAND	DU	66.00	12.00	

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	YUCCA-TWENTY-NINE PALMS	DU	115.00	12.00	
2	YUKON-INGLEWOOD	DU	66.00	16.00	
3	YUKON-INGLEWOOD	DU	66.00	4.00	
4	ZANJA-YUCAIPA	DU	115.00	33.00	
5	Rounding adjustments due to software				
6	Total		75163.00	16768.40	231.60
7					
8	Note				
9	D- Distribution				
10	T- Transmission				
11	A- Attended				
12	U- Unattended				
13					
14	Summary: Capacity:				
15	776 DU 31,620				6.00
16	25 TA 26,175				
17	163 TU 51,767				
18	964 109,562				
19					
20					
21					
22					
23					1.00
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
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.
2238	6	1				1
1120	4					2
500	2					3
840	3					4
112	4		*PEAKER	1	75	5
13	1					6
810	3					7
150	6					8
84	3		*PEAKER	1	75	9
332	2		*CUSTOMER SUBSTATION			10
59	2		*CUSTOMER SUBSTATION			11
90	3		*CUSTOMER SUBSTATION			12
840	3					13
120	6	1				14
84	4					15
5	1					16
1119	3	1				17
560	2					18
560	2					19
28	1					20
2238	6	1				21
840	3	1				22
56	2					23
56	12	1				24
280	1					25
144	1					26
133	1					27
9	3	1				28
560	2					29
560	2					30
56	2					31
560	2					32
96	4					33
2115	9	1				34
1120	4					35
45	2					36
560	2					37
11	3					38
84	3		*TEMPORARY GENORATOR	24	60	39
560	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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
28	2					1
14	1					2
840	3					3
560	2					4
560	2					5
73	3					6
500	2					7
56	2					8
2	3	1				9
840	3					10
1030	4					11
112	2					12
1030	4					13
56	2					14
840	3					15
45	2					16
2238	6	1				17
840	3					18
75	3					19
56	2					20
4476	12	1				21
840	3	1				22
56	2		*PEAKER	1	75	23
840	3					24
1120	4					25
106	4					26
840	3					27
28	2					28
840	3					29
112	4					30
2238	6	1				31
1120	4					32
600	3	1				33
59	6					34
1119	3	1				35
560	2					36
400	3					37
40	2					38
78	3					39
280	1					40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
560	2					1
560	2					2
157	6					3
560	2					4
112	4					5
3357	9					6
480	6					7
39	3					8
2800	5					9
73	3					10
560	2					11
31	6					12
1120	4					13
162	3					14
112	4					15
16	1					16
560	2					17
56	2					18
840	3					19
101	4					20
4476	12	2				21
500	2					22
1120	4					23
840	3					24
92	4	1				25
80	3					26
50	3					27
60	1					28
10	1					29
14	1					30
120	12	1				31
120	6					32
13	1					33
229	2					34
44	1					35
133	1					36
1	3					37
75	1					38
21	1					39
65	1		*CUSTOMER SUBSTATION			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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		*CUSTOMER SUBSTATION			1
45	2		*CUSTOMER SUBSTATION			2
22	1		*CUSTOMER SUBSTATION			3
258	7					4
158	2					5
5	3					6
5	1					7
17	1					8
22	1		*CUSTOMER SUBSTATION			9
250	1		*ISOLATION & STAND B	3	19	10
720	2					11
1090	4					12
270	6	1				13
163	1					14
84	3					15
24	2					16
40	2		*CUSTOMER SUBSTATION			17
56	2		*CUSTOMER SUBSTATION			18
984	12					19
163	1					20
4	1					21
2	1					22
4	3	1				23
38	4					24
			*SERVICE BANK LOAD	2	1	25
50	6	1				26
			*SERVICE BANK LOAD	2	1	27
14	1		*CUSTOMER SUBSTATION			28
14	2					29
4	1					30
180	2					31
180	2					32
75	1		*CUSTOMER SUBSTATION			33
14	1		*CUSTOMER SUBSTATION			34
2	3					35
3	1					36
			*STATION LIGHT AND P	2	1	37
5	1					38
28	1		*CUSTOMER SUBSTATION			39
90	1		*AUXILARY STATION LO	1	56	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
1680	6					1
10	7	1				2
4	1					3
28	1		*CUSTOMER SUBSTATION			4
14	1					5
2	3	1				6
10	1					7
56	2		*CUSTOMER SUBSTATION			8
22	1		*CUSTOMER SUBSTATION			9
11	1		*CUSTOMER SUBSTATION			10
14	1					11
810	3					12
56	2					13
			*AUXILARY STATION LO	2	56	14
22	1		*CUSTOMER SUBSTATION			15
4	1					16
3	1					17
45	2		*CUSTOMER SUBSTATION			18
45	2		*CUSTOMER SUBSTATION			19
46	1					20
14	1					21
14	1		*CUSTOMER SUBSTATION			22
14	1					23
2	3	1				24
56	2		*CUSTOMER SUBSTATION			25
2238	6	1				26
14	1		*CUSTOMER SUBSTATION			27
2238	6	1				28
280	1					29
56	2					30
14	1		*CUSTOMER SUBSTATION			31
14	1					32
22	1		*CUSTOMER SUBSTATION			33
129	5					34
56	2					35
101	4					36
112	4					37
14	6	1				38
13	2					39
56	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
76	3					1
24	6	1				2
14	2					3
2	3	1				4
3	1					5
28	1		*CUSTOMER SUBSTATION			6
10	1		*CUSTOMER SUBSTATION			7
80	4		*CUSTOMER SUBSTATION			8
73	3					9
84	3					10
15	6					11
14	1		*CUSTOMER SUBSTATION			12
30	1		*CUSTOMER SUBSTATION			13
84	3					14
84	3					15
90	4					16
25	2					17
5	2					18
73	3					19
101	4					20
7	1		*CUSTOMER SUBSTATION			21
24	2					22
50	2					23
5	3	1				24
2	1					25
79	6					26
3	3	1				27
6	6		*CUSTOMER SUBSTATION			28
27	2					29
9	1					30
50	2					31
112	2					32
112	4					33
84	4					34
11	1					35
56	2					36
8	1					37
5	3	1				38
84	3					39
106	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	2					1
6	3					2
81	3					3
11	1					4
84	3					5
6	1					6
25	4					7
9	1	1				8
10	1					9
10	1					10
141	6					11
38	3					12
11	1					13
8	1					14
27	2		*CUSTOMER SUBSTATION			15
56	2					16
112	4					17
8	3	1				18
159	2					19
28	2					20
25	2					21
40	2					22
28	1		*CUSTOMER SUBSTATION			23
84	3					24
28	1		*CUSTOMER SUBSTATION			25
52	2					26
42	2					27
12	6					28
12	6					29
93	4					30
59	3					31
45	2					32
19	1		*CUSTOMER SUBSTATION			33
21	2					34
20	2					35
48	2					36
40	2					37
5	2					38
45	2					39
13	6	1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
101	4					1
1	3					2
78	3					3
12	6					4
84	3					5
14	2					6
14	1		*CUSTOMER SUBSTATION			7
14	1		*CUSTOMER SUBSTATION			8
19	2					9
152	6					10
5	3	1				11
73	3					12
45	2		*CUSTOMER SUBSTATION			13
42	3					14
56	4					15
60	2					16
60	1					17
73	3					18
45	2					19
56	2					20
4	3	1				21
73	3					22
14	1					23
28	2					24
6	3		*CUSTOMER SUBSTATION			25
11	1		*CUSTOMER SUBSTATION			26
7	1		*CUSTOMER SUBSTATION			27
95	4					28
112	2					29
84	3					30
42	2					31
101	4					32
42	2					33
67	3					34
56	2					35
14	2					36
6	3	1				37
11	1		*CUSTOMER SUBSTATION			38
56	2					39
112	4					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
12	3	1				1
37	3					2
45	2					3
101	4					4
168	4		*CUSTOMER SUBSTATION			5
104	4					6
95	4					7
28	1		*CUSTOMER SUBSTATION			8
20	2					9
56	4					10
84	3					11
84	3					12
9	3	1				13
14	1		*CUSTOMER SUBSTATION			14
49	6	1				15
30	6		*CUSTOMER SUBSTATION			16
28	1					17
112	4		*CUSTOMER SUBSTATION			18
13	2					19
56	2					20
1	3	1				21
6	1		*CUSTOMER SUBSTATION			22
56	2					23
112	2					24
134	5					25
3	2					26
8	1		*CUSTOMER SUBSTATION			27
101	4					28
14	1					29
28	1		*CUSTOMER SUBSTATION			30
14	2					31
15	2					32
56	2					33
9	2					34
28	2					35
56	2					36
25	2		*CUSTOMER SUBSTATION			37
92	3					38
118	5					39
96	4					40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	6					1
70	3					2
18	6	1				3
15	3	1				4
22	1		*CUSTOMER SUBSTATION			5
73	3					6
3	6					7
1	3	1				8
6	3	1				9
45	2					10
14	1		*CUSTOMER SUBSTATION			11
6	3	1				12
101	4					13
7	1					14
7	1					15
45	2		*CUSTOMER SUBSTATION			16
96	4					17
56	2					18
84	3					19
6	3	1				20
11	1		*CUSTOMER SUBSTATION			21
10	2					22
45	2					23
10	1		*CUSTOMER SUBSTATION			24
45	2		*CUSTOMER SUBSTATION			25
45	2					26
12	3					27
100	3		*CUSTOMER SUBSTATION			28
69	3					29
14	1		*CUSTOMER SUBSTATION			30
28	2		*CUSTOMER SUBSTATION			31
28	1		*CUSTOMER SUBSTATION			32
15	3					33
14	1		*CUSTOMER SUBSTATION			34
84	3					35
12	6					36
14	1					37
5	3					38
22	3	1				39
4	3	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.
56	2					1
10	4					2
10	2					3
50	3					4
112	2					5
45	2					6
28	2					7
11	1					8
84	3					9
106	2					10
56	2					11
106	4					12
74	3					13
45	2					14
112	4					15
6	3	1				16
15	2					17
78	3					18
12	6	1				19
96	4					20
112	4					21
45	2					22
9	4					23
56	2					24
22	1		*CUSTOMER SUBSTATION			25
50	2					26
101	4					27
6	3	1				28
13	2					29
56	2					30
1	3	1				31
14	1		*CUSTOMER SUBSTATION			32
22	1					33
93	4					34
19	3	1				35
65	3					36
9	6					37
21	2					38
56	2					39
9	3	1				40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1		*CUSTOMER SUBSTATION			1
67	3					2
9	3	1				3
8	3	1				4
14	1		*CUSTOMER SUBSTATION			5
14	1		*CUSTOMER SUBSTATION			6
40	3	1				7
45	2					8
84	3					9
6	3					10
9	3	1				11
112	2					12
14	1					13
14	3					14
14	1		*CUSTOMER SUBSTATION			15
28	2					16
50	2	2	*TEMPORARY GENERATOR	9	23	17
41	2					18
15	2					19
22	1		*CUSTOMER SUBSTATION			20
82	4					21
100	4					22
78	3					23
6	1					24
4	3	1				25
4	1					26
56	2					27
84	3					28
7	6	1				29
28	2					30
6	3	1				31
10	2					32
12	3					33
2	3					34
45	2					35
6	1		*CUSTOMER SUBSTATION			36
56	2					37
12	6	1				38
14	1		*CUSTOMER SUBSTATION			39
8	3					40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3	3					1
4	1					2
101	4					3
40	2					4
9	3	1				5
6	3	1				6
6	3	1				7
2	3	1				8
11	1					9
25	2					10
56	2		*CUSTOMER SUBSTATION			11
8	1		*CUSTOMER SUBSTATION			12
25	2					13
50	2					14
56	2					15
28	2					16
101	4					17
14	2					18
5	1					19
18	2					20
56	3					21
13	1		*CUSTOMER SUBSTATION			22
28	2					23
17	2					24
56	2		*CUSTOMER SUBSTATION			25
14	1		*CUSTOMER SUBSTATION			26
21	2					27
11	2					28
5	1					29
11	1					30
2	3	1				31
48	2					32
12	6					33
112	4					34
82	6					35
56	2					36
19	6					37
17	1		*CUSTOMER SUBSTATION			38
56	2		*CUSTOMER SUBSTATION			39
112	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	6	1				1
2	3	1				2
5	3					3
101	4					4
15	3	1				5
50	2					6
28	1		*TEMPORARY GENERATOR	6	15	7
11	1					8
56	2					9
112	4					10
78	3					11
5	1					12
5	6					13
4	3	2				14
9	3	1				15
56	2					16
45	2					17
15	2					18
101	4					19
48	2					20
78	3					21
98	4					22
73	3					23
25	2					24
56	2					25
78	3					26
90	4					27
6	6	1				28
22	1	1				29
11	1					30
84	3					31
56	2					32
39	3	1				33
56	2					34
18	3					35
73	3					36
7	1					37
84	3					38
28	1		*CUSTOMER SUBSTATION			39
6	3	2				40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
40	2					1
12	9					2
42	2					3
112	4					4
149	6					5
11	1					6
56	2					7
3	3	1				8
11	1		*CUSTOMER SUBSTATION			9
56	2					10
76	3					11
56	2		*CUSTOMER SUBSTATION			12
13	1		*CUSTOMER SUBSTATION			13
20	2					14
9	6	1				15
3	3	1				16
40	2					17
8	3					18
67	3		*CUSTOMER SUBSTATION			19
56	2					20
15	6					21
28	2					22
6	3	1				23
12	6					24
101	4					25
			*STATION LIGHT LOAD			26
8	3	1				27
56	2					28
8	3	1				29
84	3					30
56	2					31
81	4					32
20	1	1				33
20	2					34
56	2					35
90	4					36
106	4					37
11	2					38
28	2					39
62	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
15	2					1
14	1					2
112	4					3
11	2					4
22	1		*CUSTOMER SUBSTATION			5
64	2					6
17	1					7
10	1					8
5	1					9
1	1					10
1	1					11
168	6		*CUSTOMER SUBSTATION			12
38	20		*CUSTOMER SUBSTATION			13
19	19		*CUSTOMER SUBSTATION			14
101	4					15
12	6	1				16
15	6					17
56	3					18
17	2					19
8	3	1				20
6	3	1				21
6	1		*CUSTOMER SUBSTATION			22
112	4					23
45	2					24
6	3					25
42	2					26
90	4					27
28	2					28
9	2					29
45	2					30
25	2					31
45	2					32
28	2					33
4	6	1				34
6	3					35
12	6					36
101	4					37
90	4					38
25	1		*CUSTOMER SUBSTATION			39
28	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
106	2					1
73	3					2
45	2					3
25	2					4
101	4					5
112	4					6
112	4					7
28	2					8
15	6	1				9
84	3					10
11	1					11
101	4					12
45	2					13
3	3	1				14
28	2		*CUSTOMER SUBSTATION			15
5	1					16
2	3	1				17
101	4					18
45	2		*CUSTOMER SUBSTATION			19
12	3		*CUSTOMER SUBSTATION			20
14	1		*CUSTOMER SUBSTATION			21
14	1					22
28	2					23
101	4					24
56	3					25
70	3					26
15	2					27
56	2					28
29	3					29
19	3					30
28	1					31
15	2					32
11	2					33
11	3					34
84	3					35
11	1		*CUSTOMER SUBSTATION			36
1	1					37
81	4					38
13	1		*CUSTOMER SUBSTATION			39
56	2		*CUSTOMER SUBSTATION			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	2					1
3	3	1				2
28	3	1				3
14	6					4
9	1		*CUSTOMER SUBSTATION			5
28	2					6
5	3	1				7
21	2					8
45	2					9
5	3					10
90	4					11
8	3	1				12
22	1		*CUSTOMER SUBSTATION			13
20	1		*CUSTOMER SUBSTATION			14
73	3					15
45	2					16
56	3					17
5	2					18
5	6					19
56	1					20
84	3					21
56	2					22
2	3	1				23
76	3					24
3	3	1				25
5	6					26
8	1					27
100	4					28
56	2		*CUSTOMER SUBSTATION			29
25	1					30
50	2					31
87	4					32
28	1		*CUSTOMER SUBSTATION			33
15	2					34
53	2					35
15	2					36
39	2		*CUSTOMER SUBSTATION			37
9	3					38
56	2					39
67	3					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1		*CUSTOMER SUBSTATION			1
14	1		*CUSTOMER SUBSTATION			2
3	3	1				3
3	2					4
22	1		*CUSTOMER SUBSTATION			5
9	1		*CUSTOMER SUBSTATION			6
12	6					7
10	3					8
28	1					9
112	4					10
9	6	2				11
112	4					12
28	1					13
48	2					14
22	1		*CUSTOMER SUBSTATION			15
56	2					16
34	1		*CUSTOMER SUBSTATION			17
56	2					18
19	3	1				19
106	4					20
14	1		*CUSTOMER SUBSTATION			21
32	2					22
45	2					23
101	4					24
56	2					25
28	2					26
81	4					27
14	1					28
28	1		*CUSTOMER SUBSTATION			29
22	1		*CUSTOMER SUBSTATION			30
56	2					31
21	2					32
6	3	1				33
12	6					34
28	1		*CUSTOMER SUBSTATION			35
14	1		*CUSTOMER SUBSTATION			36
13	1		*CUSTOMER SUBSTATION			37
13	1		*CUSTOMER SUBSTATION			38
8	1		*CUSTOMER SUBSTATION			39
73	3					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
6	3					1
10	1					2
8	3					3
6	3					4
14	1		*CUSTOMER SUBSTATION			5
6	1					6
22	1		*CUSTOMER SUBSTATION			7
28	1					8
21	2					9
56	2		*CUSTOMER SUBSTATION			10
56	2					11
56	3					12
14	1		*CUSTOMER SUBSTATION			13
27	3		*CUSTOMER SUBSTATION			14
50	2					15
9	3	1				16
23	3					17
19	3		*CUSTOMER SUBSTATION			18
95	4					19
106	4					20
11	1					21
25	3					22
11	2					23
101	4					24
101	4					25
95	4					26
56	2					27
25	2					28
50	4					29
10	3	1				30
67	3					31
6	3					32
6	3	1				33
84	3					34
15	6	1				35
40	3	1				36
56	2					37
56	2					38
25	2					39
112	2					40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2016	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
112	4					1
104	4					2
11	1		*CUSTOMER SUBSTATION			3
45	2					4
106	4					5
22	2					6
38	6					7
25	3					8
5	3	1				9
90	4					10
6	6					11
56	2		*CUSTOMER SUBSTATION			12
84	3					13
9	6					14
50	3					15
3	3		*CUSTOMER SUBSTATION			16
2	3		*CUSTOMER SUBSTATION			17
112	4		*CUSTOMER SUBSTATION			18
84	3		*CUSTOMER SUBSTATION			19
7	1		*CUSTOMER SUBSTATION			20
28	1		*CUSTOMER SUBSTATION			21
101	4					22
11	1					23
28	2					24
8	3					25
28	2					26
28	2					27
73	3					28
56	3					29
5	1					30
9	3	1	*CUSTOMER SUBSTATION			31
56	2					32
45	2					33
12	6					34
28	2					35
14	1		*CUSTOMER SUBSTATION			36
14	1		*CUSTOMER SUBSTATION			37
56	2					38
13	2					39
28	1		*CUSTOMER SUBSTATION			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
9	3		*CUSTOMER SUBSTATION			1
40	2		*CUSTOMER SUBSTATION			2
8	1		*CUSTOMER SUBSTATION			3
19	3					4
62	3					5
112	4					6
56	2		*CUSTOMER SUBSTATION			7
56	2					8
14	1		*CUSTOMER SUBSTATION			9
101	4					10
56	2		*CUSTOMER SUBSTATION			11
68	3					12
21	2					13
28	2					14
9	3					15
28	1					16
40	3	1				17
28	1					18
6	3					19
56	2					20
11	2					21
28	2		*CUSTOMER SUBSTATION			22
60	3					23
15	6					24
10	1					25
10	1					26
56	3					27
112	4					28
28	2					29
45	2					30
112	4					31
11	1					32
56	2					33
56	2					34
13	3					35
14	1					36
7	1					37
56	2					38
112	4					39
14	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1		*CUSTOMER SUBSTATION			1
6	1		*CUSTOMER SUBSTATION			2
40	2		*CUSTOMER SUBSTATION			3
40	2		*CUSTOMER SUBSTATION			4
45	2		*CUSTOMER SUBSTATION			5
45	2		*CUSTOMER SUBSTATION			6
6	3					7
22	1		*CUSTOMER SUBSTATION			8
56	2					9
101	4					10
10	2					11
56	3					12
30	3					13
25	2					14
101	4					15
11	1		*CUSTOMER SUBSTATION			16
112	2					17
56	2					18
14	1		*CUSTOMER SUBSTATION			19
101	4					20
56	2					21
6	3	1				22
76	3					23
112	4					24
11	1					25
7	1					26
17	1		*CUSTOMER SUBSTATION			27
28	2		*CUSTOMER SUBSTATION			28
70	3					29
13	2					30
106	4					31
101	4					32
5	2					33
10	1		*CUSTOMER SUBSTATION			34
50	2					35
45	2					36
56	2					37
9	9	1				38
56	2					39
5	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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.
75	4					1
25	2					2
5	3	1				3
56	2					4
12	9					5
56	2					6
56	2					7
3	1					8
56	3					9
9	1					10
45	2					11
14	1		*CUSTOMER SUBSTATION			12
56	2					13
42	2					14
5	3					15
22	1		*CUSTOMER SUBSTATION			16
9	3	1				17
14	1		*CUSTOMER SUBSTATION			18
25	3					19
14	1					20
13	1		*CUSTOMER SUBSTATION			21
11	1					22
28	2		*CUSTOMER SUBSTATION			23
45	2		*CUSTOMER SUBSTATION			24
14	1		*CUSTOMER SUBSTATION			25
28	1		*CUSTOMER SUBSTATION			26
13	3					27
27	3	1				28
1	1					29
13	1					30
72	3					31
28	2					32
21	2					33
21	2					34
56	2					35
28	2					36
4	3	1				37
5	1					38
84	3					39
101	4					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.
45	2					1
84	3					2
28	2					3
13	3					4
-38						5
109562	2564	122		54	457	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

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	Accounts Receivable from Associated Companies	Edison International	146	210,158,428
3	Capital Stock Expense	Edison International	214	87,997
4	Donations	Edison International	426.1xx	23,292,611
5	Exp for Certain Civic, Political, and Rel. Activit	Edison International	426.4xx	5,001,452
6	Other Deductions	Edison International	426.5xx	536,413
7	Other Interest Expense	Edison International	431	1,053,553
8	Dividends Declared	Edison International	438	611,158,391
9	Operations Supervision & Engineering	Edison International	517	8,026
10	Miscellaneous Nuclear Power Expenses (Major Only)	Edison International	524	53
11	Admin and Gen Salaries/Office Supp. and Expenses	Edison International	920/921	1,228,945
12	Outside Services Employed	Edison International	923	20,494,883
13	Employee Pension and Benefits	Edison International	926	26,465
14	Miscellaneous General Expenses	Edison International	930.2	4,878,995
15	Rent	Edison International	931	27,351
16				
17			TOTAL	877,953,563
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Other Special Funds	Edison International	128.5	491
22	Accounts Receivable from Associated Companies	Edison International	146	-5,873,137
23	Regulatory Debits	Edison International	407.3	453,692
24	Taxes Other Than Inc. Taxes, Utility Op. Income	Edison International	408.1xx	150,612
25	Expenses of Non-Utility Ops	Edison International	417.1	5,396
26	Donations	Edison International	426.1xx	93,729
27	Other Deductions	Edison International	426.5xx	965
28	Other Electric Revenues	Edison International	456	2,470,826
29	Operation Supervision and Engineering	Edison International	535	18,970
30	Other Expenses	Edison International	557	177,183
31	Supervision (Major Only)	Edison International	901	31,415
32	Admin & Gen Salaries/Ofc Support and Expenses	Edison International	920/921	2,336,168
33	Outside Services Employed	Edison International	923	783,843
34	Injuries and Damages	Edison International	925	22,724
35	Employee Pension and Benefits	Edison International	926	6,053,126
36	Miscellaneous General Expenses	Edison International	930.2	24,731
37				
38			TOTAL	6,750,733
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Accounts Receivable from Associated Companies	Edison Energy Support Services	146	-1,009,017

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	Taxes Other Than Inc. Taxes Utility Op. Income	Edison Energy Support Services	408.1xx	5,497
4	Other Electric Revenues	Edison Energy Support Services	456	41,499
5	Demonstrating and Selling Exp (Major Only)	Edison Energy Support Services	912	3,144
6	Admin & Gen Salaries/Ofc Supp and Expenses	Edison Energy Support Services	920/921	233,831
7	Injuries and Damages	Edison Energy Support Services	925	818
8	Employee Pension and Benefits	Edison Energy Support Services	926	134,379
9				
10			TOTAL	-589,851
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounts Receivable from Associated Companies	Edison Mission Group	146	17,649
22	Taxes Other Than Inc Taxes, Utility Op. Income	Edison Mission Group	408.1xx	12,551
23	Donations	Edison Mission Group	426.1xx	2,547
24	Other Deductions	Edison Mission Group	426.5xx	378
25	Other Electric Revenues	Edison Mission Group	456	84,527
26	Admin and Gen Salaries/Ofc Support	Edison Mission Group	920/921	281,798
27	Outside Services Employed	Edison Mission Group	923	1,567
28	Injuries and Damages	Edison Mission Group	925	1,895
29	Employee Pension and Benefits	Edison Mission Group	926	246,245
30	Miscellaneous General Expenses	Edison Mission Group	930.2	40,341
31				
32			TOTAL	689,498
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Accounts Receivable from Associated Companies	Edison Capital	146	2,086
3	Taxes Other Than Inc.Taxes,Utility Op. Income	Edison Capital	408.1xx	40,341
4	Donations	Edison Capital	426.1xx	1,829

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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	Other Deductions	Edison Capital	426.5xx	273
6	Other Electric Revenues	Edison Capital	456	314,438
7	Admin and Gen Salaries/Ofc Supp&Expenses	Edison Capital	920/921	1,065,829
8	Outside Services Employed	Edison Capital	923	1,135
9	Injuries and Damages	Edison Capital	925	6,132
10	Employee Pension and Benefits	Edison Capital	926	194,131
11	Miscellaneous General Expenses	Edison Capital	930.2	2,509
12				
13			TOTAL	1,628,704
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounts Receivable from Associated Companies	Edison Energy Group	146	53,456
22	Taxes Other Than Inc.Taxes Utility Op. Income	Edison Energy Group	408.1xx	17,135
23	Donations	Edison Energy Group	426.1xx	2,305
24	Other Deductions	Edison Energy Group	426.5	411
25	Other Electric Revenues	Edison Energy Group	456	196,918
26	Other Expenses	Edison Energy Group	557	334
27	Miscellaneous Distribution Expenses	Edison Energy Group	588	2,676
28	Demonstrating and Selling Expenses (Major Only)	Edison Energy Group	912	4,348
29	Admin & Gen Salaries/Ofc Supp and Exp	Edison Energy Group	920/921	242,636
30	Outside Services Employed	Edison Energy Group	923	1,808
31	Injuries and Damages	Edison Energy Group	925	2,647
32	Employee Pension and Benefits	Edison Energy Group	926	90,642
33	Miscellaneous General Expenses	Edison Energy Group	930.2	3,421
34				
35			TOTAL	618,736
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2016	End of 2015/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				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
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39				
40				
41				
42				

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

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 3 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 4 Column: a

Directly Charged: all costs associated with services are billed to the utility. Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429 Line No.: 5 Column: a

Directly Charged: all costs associated with services are billed to the utility. Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429 Line No.: 6 Column: a

Directly Charged: all costs associated with services are billed to the utility. Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429 Line No.: 7 Column: a

Directly Charged: all costs associated with services are billed to the utility. Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429 Line No.: 8 Column: a

Directly Charged: all costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 9 Column: a

Directly Charged: all costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 10 Column: a

Directly Charged: all costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 11 Column: a

Directly Charged: all costs associated with services are billed to the utility. Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 12 Column: a

Directly Charged: all costs associated with services are billed to the utility. Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees. Equity Investment: this allocation method is based on the equity of each affiliate.

Schedule Page: 429 Line No.: 13 Column: a

Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 14 Column: a

Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429 Line No.: 15 Column: a

Directly Charged: all costs associated with services are billed to the utility.

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

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 22 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 23 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 24 Column: a

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Equity Investment: this allocation method is based on the equity of each affiliate.
Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 25 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 26 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429 Line No.: 27 Column: a

Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429 Line No.: 28 Column: a

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment: this allocation method is based on the equity of each affiliate.
Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 29 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 30 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 31 Column: a

Directly Charged: all costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 32 Column: a

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment: this allocation method is based on the equity of each affiliate.
Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 33 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 34 Column: a

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 35 Column: a

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 36 Column: a

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment: This allocation method is based on the equity of each affiliate.

Schedule Page: 429.1 Line No.: 2 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.1 Line No.: 3 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 4 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 5 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.1 Line No.: 6 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 7 Column: a

Directly Charged: all costs associated with services are billed to the utility. Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees. Equity Investment: this allocation method is based on the equity of each affiliate. Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 8 Column: a

Directly Charged: all costs associated with services are billed to the utility. Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 21 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.1 Line No.: 22 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 23 Column: a

Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429.1 Line No.: 24 Column: a

Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429.1 Line No.: 25 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 26 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 27 Column: a

Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 28 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 29 Column: a

Directly Charged: all costs associated with services are billed to the utility.Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 30 Column: a

Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.

Schedule Page: 429.2 Line No.: 2 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.2 Line No.: 3 Column: a

Directly Charged: all costs associated with services are billed to the utility. Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees. Equity Investment: this allocation method is based on the equity of each affiliate. Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 4 Column: a

Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429.2 Line No.: 5 Column: a

Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429.2 Line No.: 6 Column: a

Directly Charged. All costs associated with services are billed to the utility.
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Equity Investment: this allocation method is based on the equity of each affiliate.

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Schedule Page: 429.2 Line No.: 7 Column: a

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Schedule Page: 429.2 Line No.: 8 Column: a

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Schedule Page: 429.2 Line No.: 9 Column: a

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Schedule Page: 429.2 Line No.: 10 Column: a

Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees. Number of Employees: this method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 11 Column: a

Multi Factor: this method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees. Equity Investment: this allocation method is based on the equity of each affiliate.

Schedule Page: 429.2 Line No.: 21 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.2 Line No.: 22 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
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Schedule Page: 429.2 Line No.: 23 Column: a

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Schedule Page: 429.2 Line No.: 24 Column: a

Multi Factor. This method is based on a formula using each affiliate’s proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.

Schedule Page: 429.2 Line No.: 25 Column: a

Directly Charged. All costs associated with services are billed to the utility.
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Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 26 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.2 Line No.: 27 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.2 Line No.: 28 Column: a

Directly Charged. All costs associated with services are billed to the utility.

Schedule Page: 429.2 Line No.: 29 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 30 Column: a

Directly Charged: all costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 31 Column: a

Directly Charged. All costs associated with services are billed to the utility.
Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 32 Column: a

Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Number of Employees. This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 33 Column: a

Multi Factor. This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets, and Number of Employees.
Equity Investment. This allocation method is based on the equity of each affiliate.

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